Generation Outage Dynamic Contingency Analysis Using Frequency Prediction

by

Muhammad Akhtar Chaudhry

A Thesis Presented to the

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In Partial Fulfillment of the
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This thesis is written by **Muhammad Akhtar Chaudhry** under the direction of his Thesis Advisor and approved by his Thesis Committee, has been presented to and accepted by the Dean of the College of Graduate Studies, in partial fulfillment of the requirements for the degree of **MASTER OF SCIENCE IN ELECTRICAL ENGINEERING.**

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This thesis is dedicated to my beloved Parents.

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خلاصة الرسالة

اسم الطالب الكامل : محمد أختر شودري

عنوان الدراســـــة : تحليل الأسباب الديناميكية لتوقف التوليد باستعمـــال توقع التردد

مجال التخصـــــص : هندسة أنظمة الطاقة الكهربائية

تاريخ الشهـــادة : يونيو ١٩٨٨

يقترح البحث معادلة أكثر شمولية لتوقع معدل تردد الشبكة الكهربائية . ان هذه المعادلة تتنبأ بأقل مستوى للتردد بعد حصول أي خلل ، وكذلك الوقت اللازم للوصول الى ذلك المستوى بعد حدوث أي خلل كبير في الشبكة مثل توقف مجموعة من الوحدات المولدة عن العمل أو انقطاع بعض خطوط الربط المهمة . ويعبر عن هذه الصيغة بواسطة ثوابت معمل الطاقة ، أو حجم الخلل الناتج ، أو بواسطة نقاط التحديد لمرحلات تنظيم الحمل . كما وأنها تتوقع الوقت الذي يعزل فيه بعض الحمل وكذلك الطاقة الكهربائية الحقيقية والميكانيكيـــة للوحدات المولدة حيث يعبر عنها كدوال تعتمد على الزمن . ولقد قورنـــت في هذا البحث نتائج هذه الصيغة المتوقعة للتردد مع متوسط تردد الشبكـــة المحصول عليه بواسطة المحاكاة .

ولقد أستعملت صيغة التردد هذه مع برنامج تدفق الطاقة المفكوك التقارن السريع للحصول على تدفق ديناميكي للطاقة حيث استعمل في تحليل توقف توليد الطاقة وامكانية حدوث طوارئ الحمل .

ويقترح البحث معاملات لفعالية تردد النظام بغرض مقارنة وتصنيف الحالات الطارئة الحرجة . ولقد تم انجاز بعض التحاليل لحالات الطوارئ حيـــث تم تصنيفها أيضا .

وتم أيضا في هذا البحث تصميم اسلوب لعزل بعض الحمل مشروط بمعدل تغيـر تردد الشبكة وقورن هذا الاسلوب مع أحد الأساليب الموجودة سابقا لهذا الغرض.

درجة الماجستير في العلـوم

جامعة الملك فهد للبترول والمعادن
الظهران ، المملكة العربية السعودية

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ABSTRACT

Muhammad Akhtar Chaudhry

GENERATION OUTAGE DYNAMIC CONTINGENCY ANALYSIS USING FREQUENCY PREDICTION

Major Field : Power System Engineering

June 1988

A more general average system frequency prediction formula has been proposed in this thesis. The frequency formula predicts the post disturbance minimum frequency and its time of occurance following a major disturbance such as loss of a block of generating units or major tie lines. This closed form frequency formula is in terms of the power plant parameters, disturbance sizes, and load shedding relay set-points. It also predicts the time at which load is shed and real electrical and mechanical power of generators as a function of time. The results of frequency prediction formula have been compared with the average system frequency obtained by simulation.

This frequency formula was incorporated in a fast decoupled load flow program to produce a dynamic load flow which was used to perform loss of generation/load contingency analysis.

Two frequency performance Indices have been proposed for comparison and ranking of critical contingencies. Several contingencies analysis were performed and these contingencies were ranked.

A rate of change of frequency dependence load shedding scheme was designed and compared with one of the existing load shed schemes.

MASTER OF SCIENCE

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CHAPTER 1

INTRODUCTION

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1.1 GENERAL

Ideally, the loads in a power system must be fed at voltages and frequency which are held within close tolerances. Whenever there is any major disturbance in a power system, the system conditions must be altered if the system is to continue to be in operation. The frequency and voltages in the system may go outside normal specified limits when the system is not in a position to cater to its load owing to the loss of an important transmission line or a large generating unit. Most of the power systems are designed and operated such that any single initial failure event will not cause the system to end up in an emergency mode of operation. Transmission line failures cause changes in the flows and voltages on the remaining transmission equipment connected to the system. The analysis of transmission failure requires methods to predict the flows and voltages so as to be sure they are within their respective limits.

Generation failures can also cause flows and voltages to change in the transmission system, in addition to dynamic problems involving abnormal system frequency trajectories which may cause load shedding to occur. Operating personnel must know the transient and steady state effects of the line or generation outages so as to provide appropriate preventive or corrective control measures.

1.2 PROBLEM STATEMENT

Some of the problems that occur on a power system can cause serious trouble within such a short time period that the operator could not take action fast enough. This is often the case with cascading failures. Because of this aspect of system operation, modern energy control centers are equipped with contingency analysis programs that predict possible system troubles before they arise. These programs are based on a model of power system and are used to study outage events for a set of probable contingencies. The result of contingency analysis is used to develop security enhancement approaches to improve the system security level and also alarm the operators to any potential overloads or out-of-limit conditions.

Most of the emphasis in the literature on contingency analysis have been placed on steady state bus voltage violation, reactive power violation and line overloads caused by generation/line outages [1]. However, the loss of a large generating unit results in frequency transient which may cause load shedding and other cascading events depending upon the severity of initiating event and the state of power system. Almost all the contingency analysis reported in the literature, so far, ignore this aspect of the problem. The most common approaches proposed in the literature for studying/analyzing the post transient frequency phenomena were based on simulation via numerical integration of the dynamic equations to assess the frequency transients. Typically the long term dynamic simulation or transient/mid term stability programs have been used.

Therefore, there is a need for the development of fast dynamic contingency analysis program which can be used to evaluate the effect of loss of generation or load contingencies on the frequency transients and this is the subject of this thesis.

1.3 LITERATURE REVIEW

1.3.1 Steady State Contingency Analysis

Several researchers have studied different aspects of contingency analysis. These include fast solution methods [2], automatic contingency event selection [1,3], and automatic initialization of contingency load flows using actual system data and state estimation procedures, development of new performance indices etc [1,4].

The problem of studying hundreds of possible contingencies becomes very difficult to solve if it is desired to present the results quickly so that corrective action can be taken. Therefore, several researchers have developed computer algorithms for quickly identifying those contingencies which may cause out-of-limit conditions so as to reduce the number of contingencies that need to be evaluated in more detail when assessing the power system's security [1].

However, almost all the contingency analysis research work reported in the literature have concentrated on steady state security. Dynamic performance of the power system is also very important. So far, all the approaches presently being used to study system dynamic performance such as frequency transients or long term dynamics following contingencies are based on simulation [2,5]. A fast method for evaluating effect of loss of generation/load contingencies on frequency trajectories is needed.

1.3.2 Dynamic Contingency Analysis

E.Handschin proposed suitable models for dynamic contingency analysis for medium or long term dynamics [2]. The problem of fast numerical integration methods for minimal computer simulation time requirements was treated in some detail. The dynamic behaviour after a large contingency occuring in a test system interconnected to a large power system was studied with low speed dynamic model. The only contingency considered was loss of, 100 MW generated power corresponding to 20 % of prefault generation. They also proposed a new structure of the boiler control which leads to an improved dynamic response after large disturbances.

M.Lotfalian et al [6] developed an inertial and governor load flow programs which capture a snapshot of the transient phenomenon for the loss of generation contingencies. However, their approach is limited since it applies to only two specific instants of the midterm stability program namely the instant immediately following the loss of generation and also the steady state condition in which redistribution of the generation lost is determined by the governor characteristics.

In ref. [7], an average system frequency formula was used to predict post disturbance maximum frequency deviation and minimum frequency without the need for simulation. Only single contingencies were handled and load shedding was not incorporated.

1.3.3 Load Shedding

Whenever a contingency occurs, the frequency and voltages of the system alter. There is a risk of damage to equipment or a cascading outage resulting in a blackout of the entire system. Abnormal system frequency can cause severe stresses to power plants and their auxiliaries. Under-frequency load shedding scheme have been incorporated by several utilities to take care of this problem. Load shedding schemes are usually implemented after extensive simulation studies [8,9]. Load shedding is also used to relieve several overloaded lines but this has been treated as a steady state problem. Frequency transients resulting from the loss of generator/load were not considered.

Very little emphasis in the literature has been directed to the optimal load shedding problem during frequency transients using simulation. Robert C.Durbeck [8] presented the results of a simulation study of five different load shedding schedules using a comprehensive long term dynamic simulator.

In 1980, D.W.Smaha [10] discussed the optimum load shed scheme design used by the Southern Electric System, Birmingham. This design method takes advantage of a transient stability computer program to analyze voltage and frequency responses of a model system for variation in number of frequency steps, frequency set points, amount of load shed per step, and fixed time delay per step for several different levels of initial system conditions. The authors of [8] and [10] proposed load shedding schedules by using a comprehensive long-term dynamic simulator. However, this involves a lot of computation time.

Most of the emphasis on load shedding studies reported in the literature was given for development of programs for optimum load shedding for relieving line overload problems under steady state conditions [11,12]. Frequency transients resulting from the tripping or connecting of loads were not considered. Also the approaches used to evaluate load shedding schemes relied mostly on very time consuming simulation programs to simulate the frequency transients. A dynamic contingency analysis program which can predict the transient effect of loss of generator/load will be very useful for studying load shed schemes.

1.4 SCOPE OF THESIS

The tasks to be performed under this topic are divided into following three categories:

1.4.1 Development of Frequency Prediction Formula

In this thesis, a more general frequency prediction formula overcoming the limitation of ref. [7] has been proposed. This closed form frequency formula is in terms of the power plant parameters, disturbances size, and load shedding relay set-points. The frequency prediction formula incorporates:

(i) Load shedding Relay set points

(ii) Multiple contingencies

The frequency formula predicts frequency deviation as a function of time starting immediately after the first disturbance (sudden loss/increase of load or loss of generation). It can also predict minimum frequency f_{min}, time of occurance of minimum frequency t_{min} and the time at which load is shed $t_{\ell s}$. It also predicts the real electrical and mechanical power of generator as a function of time.

Validation Tests

The results of frequency prediction formula are compared with the average system frequency simulation.

1.4.2 Development of a Dynamic Load Flow Program

The average system frequency formula is incorporated in a fast decoupled load flow program to produce a dynamic load flow program which can be used to perform loss of generation/load contingency analysis. The method proposed can be used to provide a fast assessment of the impact of several cases of loss of generation/load contingencies on the performance of power system frequency and line flows.

The dynamic load flow program is used to compute the following during the time interval $0 < t < t_{min}$.

(a) Bus angle $\theta(t)$

(b) Bus voltages $v(t)$

(c) Line flows $P_{jk}(t)$

(d) Generator real and reactive power

$P_{ek}(t)$,$Q_{ek}(t)$

This approach is more general than that proposed by ref. [6].

1.4.3 Dynamic Contingency Analysis

a) Two performance Indices are defined for comparing and ranking of critical contingencies based on:

(1) Amount of disturbance
(MW lost due to disturbance)

(2) The minimum frequency deviation

(3) Margin to deficiency ratio

(4) Amount of load shed

b) Several contingency analysis are performed and these contingencies are ranked. This ranking is compared with the ranking of contingencies based on real power performance index reported in literature.

CHAPTER 2

DEVELOPMENT OF FREQUENCY PREDICTION FORMULA

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DEVELOPMENT OF FREQUENCY PREDICTION FORMULA

2.1 INTRODUCTION

The prediction of maximum frequency deviation of an electric power system following a major disturbance is of interest to engineers because of the effect of abnormally low frequency on the generating unit. The maximum frequency deviation is also of importance in system planning studies. In this chapter, a more general frequency prediction formula overcoming the limitation of ref. [7] is derived. This closed form frequency formula is in terms of power plant parameters and disturbance size. The concept of average system frequency is used for frequency prediction to filter out synchronizing oscillation among the generating units. All the units are assumed to be operating at the same speed after the disturbance.

Since the boiler time constants are long compared with the time range of interest, the boiler dynamics are neglected. However, the governor-steam chest and turbine dynamics of each power plant are included.

2.2 FREQUENCY PREDICTION DYNAMIC MODEL

The typical models used to represent power systems in studies involving the average system frequency deviation following a major disturbance are non-linear and closed loop. The closed loop model, shown in Fig. 2.1, cannot be used to derive an explicit formula for average system frequency prediction as a function of time and system parameters because of the valve area and valve rate limits.

In this thesis, the approach of ref. [7] to modelling the governor valve motion is modified. This includes the effect of valve rate limiting and gives reasonable accuracy for both small and large margin-to-deficiency ratios. The margin-to-deficiency ratio (MDR) is defined as the ratio of power plant margin to the size of disturbance.

Assumptions

The frequency prediction formula is derived on the basis of the following assumptions.

1. Perturbations in system or power plant variables about the pre-disturbance point are considered.

2. The throttle pressure of each power plant is constant during the time range of interest.

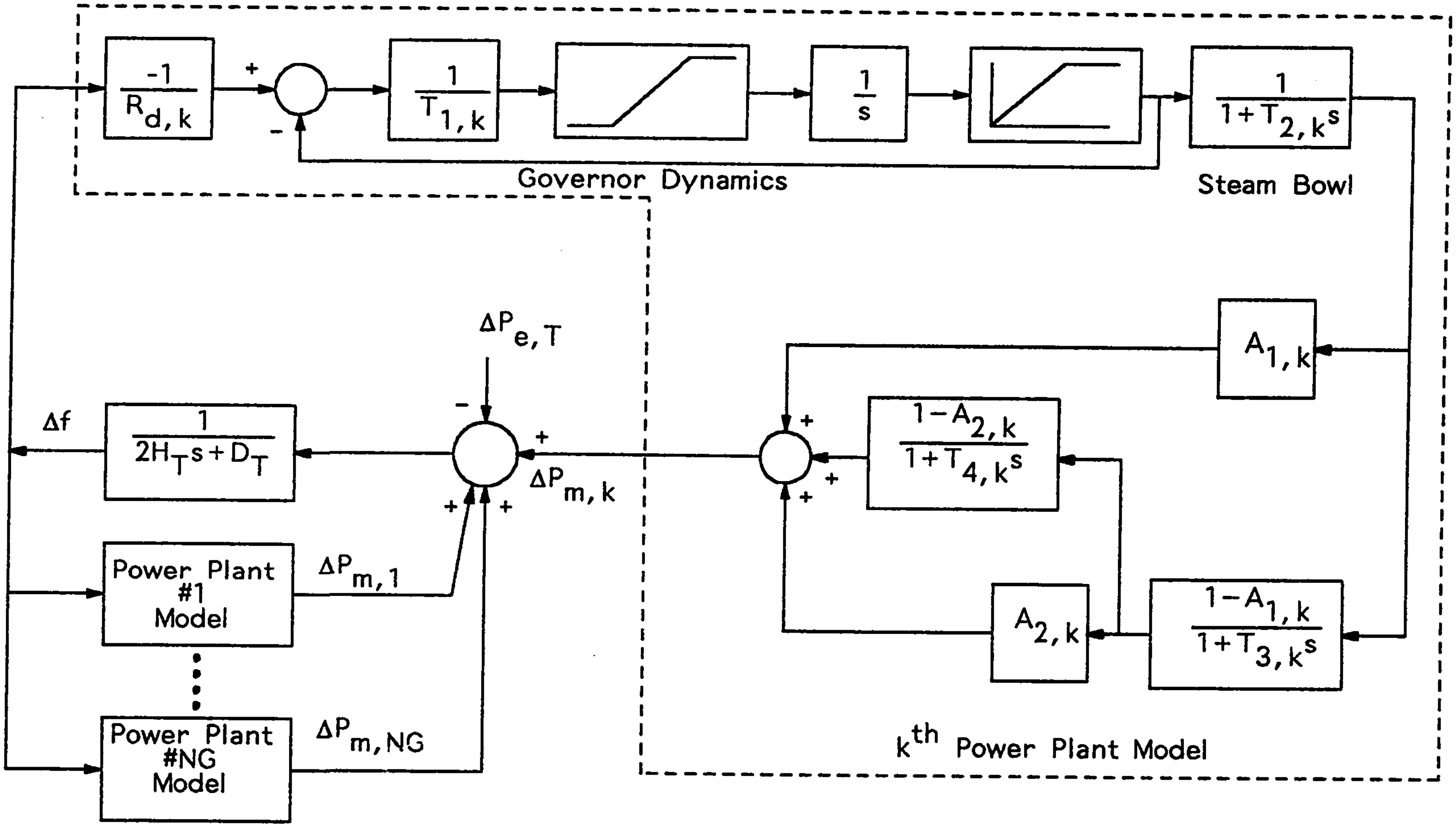

Fig. 2.1: Close Loop Non-linear Governor-Steam Turbine Model

3. The enthalpy drop of the turbine for each power plant is constant during the time range of interest.

4. Frequency dependence of loads are neglected.

These assumptions are necessary in order to obtain a realistic algebraic formula which is not too complicated.

In major disturbances in which there is a significant frequency deviation, the variation in throttle pressure is small, typical deviations are 5% or less for a frequency deviation of 1 Hz. Thus the effect of the initial pressure limiter, which adjusts the governor valve area limit, to prevent deviations in throttle pressure of more than ±5 , is not modeled.

The exclusion of the frequency dependence of the loads may be justified by the fact that, typically the effect of frequency on load is of the order of 1% per 1 Hz and such a change will affect the results only by a small amount and increase the degree of complexity of the algebraic formula. If however, the application requires its inclusion, it can be included.

It is also assumed that the only input to the governor control valve is the frequency error, hence the power set point is not changed by Automatic Generation Control or the power plant operator.

It is observed from simulation of power plant dynamic performance following a step change in load, that the governor valve motion can be approximated by a delayed ramp for the time interval between the occurance of the any disturbance and the time at which the maximum frequency deviation occur, if there is no valve area limit. If the valve reaches its area limit, then its response can be approximated as shown in Fig 2.2.

Since the delayed time of ramp is very small, it is neglected. The modified governor valve motion is shown in Fig. 2.3. The rate of change of valve area, without governor valve area limiting is dependent on

- The magnitude of initial disturbance
- The inertia constants
- Governor droop
- Time constant of power plants

The modified form of the valve motion is given by [7]:

$$\Delta A_{v,k} \equiv R_{v,k} \left[t\,U(t) - (t-T_{d,k})\,U(t-T_{d,k}) \right] \qquad (2.1)$$

where

$R_{v,k}$ = Rate of change of valve area

$U(t)$ = unit step function

$T_{d,k}$ = Time at which the valve reaches its valve area limit

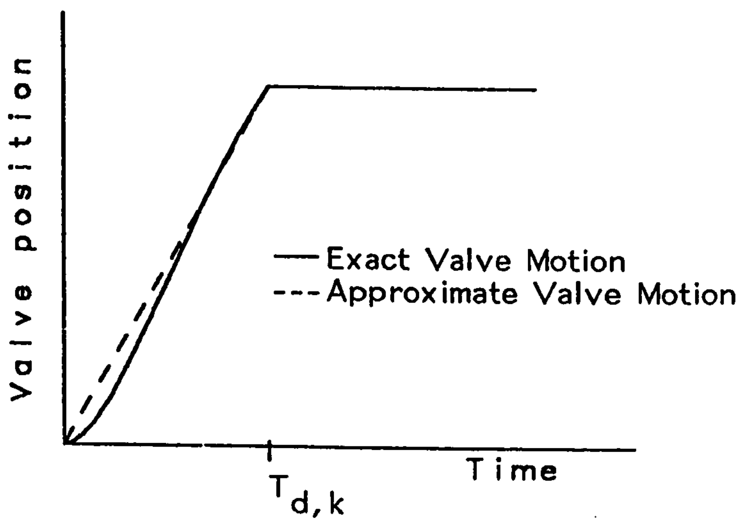

Fig. 2.2: Governor Valve Motion without valve rate limiting.

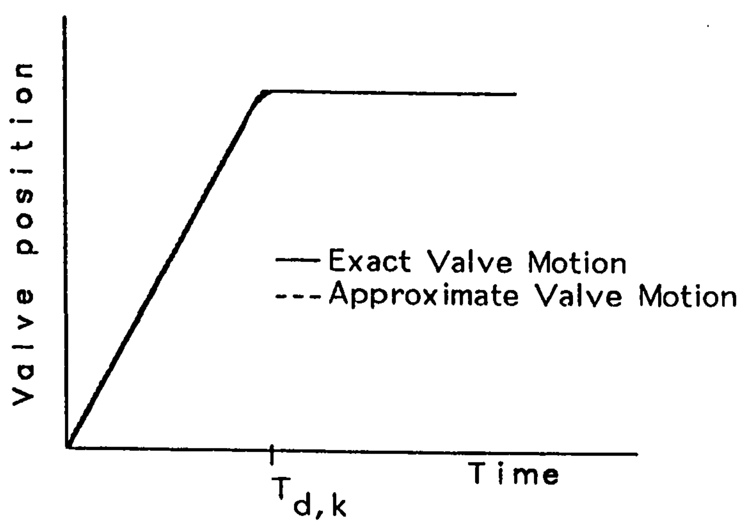

Fig. 2.3: Modified Governor Valve Motion with valve rate limiting.

At the time of occurrence of disturbance, the change in frequency $\Delta\omega$ and change in mechanical power ΔP_m is zero, so, $\Delta\dot{\omega}$ is given as:

$$\Delta\dot{\omega} = \frac{-\Delta P_e}{2H_T}$$

The input to the governor becomes

$$\Delta\omega = \frac{\Delta P_e}{2H_T R_{d,k}}$$

or

$$\Delta\omega = \frac{\Delta P_L}{2H_T R_{d,k}}$$

The governor valve area is dependent on this input and its dynamic response (approximated by ξ_k dependent on governor time constant $T_{1,k}$ and feed back loop), so, rate of change of valve area is given as:

$$R_{v,k} = \begin{bmatrix} \dfrac{\xi_k \Delta P_L}{2H_T R_{d,k}} & \text{if} \quad R_{\ell min,k} \le \dfrac{\xi_k \Delta P_L}{2H_T R_{d,k}} \le R_{\ell max,k} \\[2ex] R_{\ell max,k} & \text{if} \quad \dfrac{\xi_k \Delta P_L}{2H_T R_{d,k}} \ge R_{\ell max,k} \\[2ex] R_{\ell min,k} & \text{if} \quad \dfrac{\xi_k \Delta P_L}{2H_T R_{d,k}} \le R_{\ell min,k} \end{bmatrix} \qquad (2.2)$$

$$T_{d,k} = \frac{M_k}{R_{v,k}}$$

$$M_k = \begin{bmatrix} P_{emax,k} - P^0_{e,k} & \text{if } \Delta P_L > 0 \\ P_{emin,k} - P^0_{e,k} & \text{if } \Delta P_L < 0 \end{bmatrix}$$

ΔP_L = Magnitude of the initial disturbance

ξ_k = A constant whose value is dependent on the response of characteristics of the power plant

Using the approximate ramp representation for the valve motion, the closed loop non-linear model shown in Fig. 2.1 can be transformed into the open loop model as shown in Fig. 2.4.

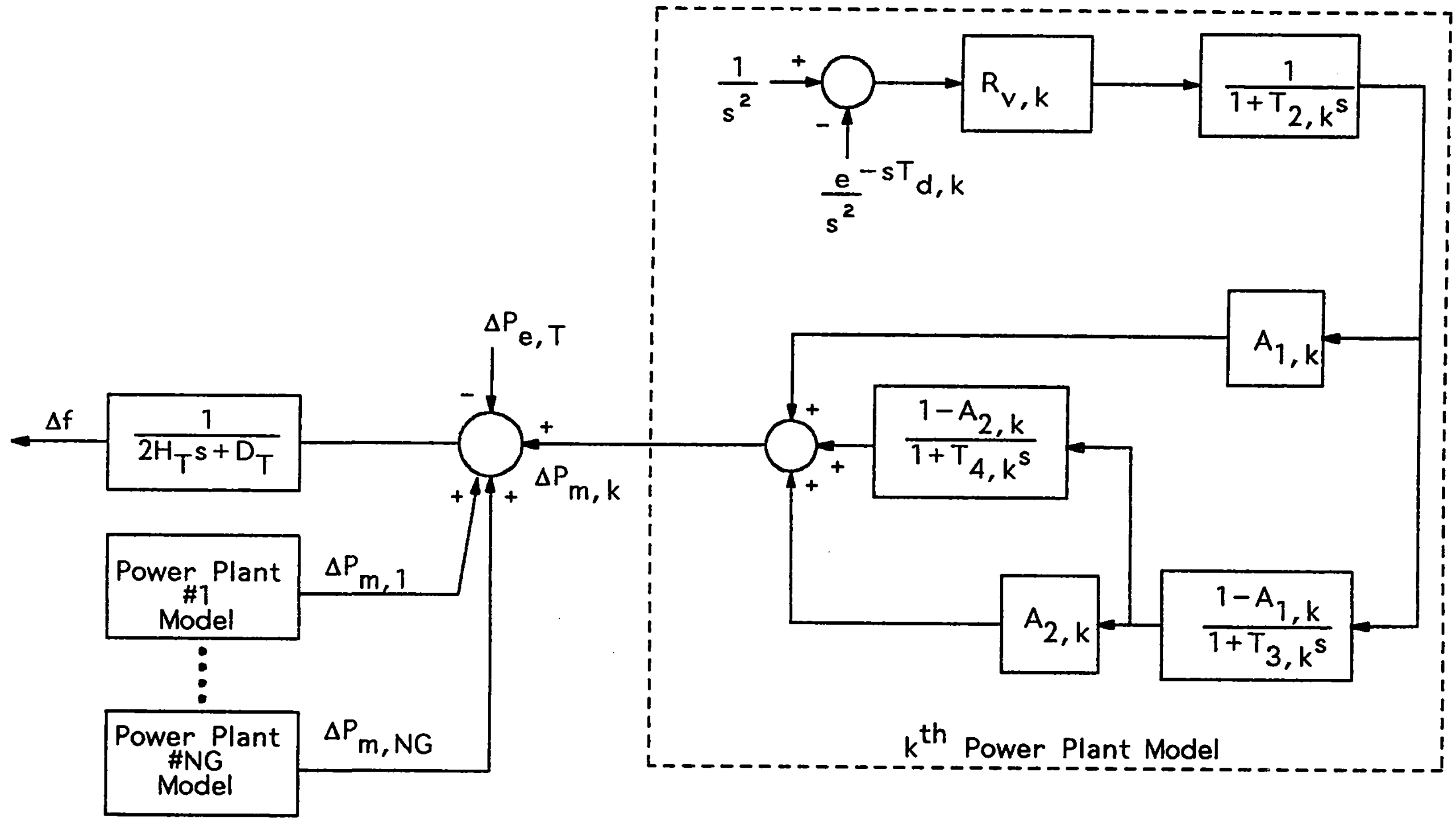

Fig. 2.4: Approximate Open Loop Governor-Steam Turbine Model

2.3 DERIVATION OF FREQUENCY PREDICTION FORMULA

The dynamic equation for k^{th} power plant following a major disturbance is given by

$$2H_k\dot{\omega}_k + D_k\omega_k = P_{m,k} - P_{e,k} \tag{2.3}$$

The basic assumption in the average system frequency concept is that all the power plants can be represented by a single frequency ω. The average system frequency is defined by

$$\left[2 \sum_k H_k s + \sum_k D \right] \omega = \sum_k P_{m,k} - \sum_k P_{e,k} \tag{2.4}$$

Since all variables are in p.u., therefore

$$f = \omega$$

$$\omega(s) = \frac{P_{m,T} - P_{e,T}}{2H_T s + D_T} \tag{2.5}$$

Where

$$H_T = \sum_k H_k$$

$$D_T = \sum_k D_k$$

$$P_{m,T} = \sum_k P_{m,k}$$

$$P_{e,T} = \sum_{k} P_{e,k}$$

Since the analysis involves only changes in variables about a point, the above equation can be written as:

$$\Delta\omega(s) = \frac{\Delta P_{m,T} - \Delta P_{e,T}}{2H_T s + D_T} \tag{2.6}$$

The transfer function relating the change in frequency to the size of disturbance was derived from the open loop model of Fig. 2.4 and given as:

$$\Delta\omega(s) = \sum_{k=1}^{NG} R_{v,k} \left[\frac{C_{o,k}}{s} + \frac{C_{1,k}}{s^2} + \frac{C_{2,k}}{s+\frac{1}{T_{2,k}}} + \frac{C_{3,k}}{s+\frac{1}{T_{3,k}}} + \frac{C_{4,k}}{s+\frac{1}{T_{4,k}}} + \frac{C_{5,k}}{s+\frac{D_T}{2H_T}} \right] \left[e^{-s} - e^{-sT_{d,k}} \right] - \frac{\Delta P_L}{s(2H_T s + D_T)} \tag{2.7}$$

The average system frequency prediction was calculated by taking inverse Laplace transform of the above transfer function, given as:

$$\Delta\omega(t) = \sum_{k=1}^{NG} R_{v,k} \Big[C_{o,k} [\, U(t) - U(t-T_{d,k}) \,]$$

$$+ C_{1,k} \left[t\, U(t) - (t-T_{d,k})\, U(t-T_{d,k})\right]$$

$$+ \sum_{j=2}^{4} C_{j,k} \left[e^{-a_{j,k}t} U(t) - e^{-a_{j,k}(t-T_{d,k})} U(t-T_{d,k})\right]$$

$$+ C_{5,k} [e^{-bt}\, U(t) - e^{-b(t-T_{d,k})}\, U(t-T_{d,k})] \Big]$$

$$- \frac{\Delta P_L}{D_T} \left[1 - e^{-bt} \right] \qquad (2.8)$$

Where

$$C_{o,k} = \frac{1}{D_T}\Big[A_{1,k}(T_{3,k}+T_{4,k})+A_{2,k}(1-A_{1,k})T_{4,k} - \frac{2H_T}{D_T}$$

$$- (T_{2,k}+T_{3,k}+T_{4,k})\Big]$$

$$C_{1,k} = \frac{1}{D_T}$$

$$C_{j,k} = -\frac{T_{j,k}^2}{Z_{j,k}}\left[\frac{A_{1,k}Y_{3j,k}Y_{4j,k}+A_{2,k}(1-A_{1,k})Y_{4j,k}+(1-A_{1,k})(1-A_{2,k})}{\prod\limits_{\substack{i=1\\ i\neq j}}^{4} Y_{ij,k}}\right]$$

$$Y_{ij,k} = 1 - \frac{T_{i,k}}{T_{j,k}} \qquad j = 2 \rightarrow 4$$

$$\prod_{\substack{i=2 \\ i \neq j}}^{4} Y_{ij,k} = \left[\begin{array}{l} \text{Product of all terms such as } Y_{ij,k} \\ \text{for } j = 2 \rightarrow 4 \qquad j \neq i \end{array} \right]$$

$$C_{5,k} = \frac{(2H_T)^2}{Z_{2,k} D_T^2} \left[A_{1,k} + \frac{2H_T}{Z_{3,k}} A_{2,k}(1 - A_{1,k}) + \frac{(2H_T)^2}{Z_{3,k} Z_{4,k}} (1 - A_{1,k})(1 - A_{2,k}) \right]$$

$$Z_{j,k} = 2H_T - D_T \, T_{j,k}$$

$$a_{j,k} = \frac{1}{T_{j,k}}$$

$$b = \frac{D_T}{2H_T}$$

The frequency prediction formula given by equation (2.8) is a combination of step, ramp and exponentional functions. The summation term relates to the mechanical power and the remaining term relates to the effect of disturbance. Both the terms finally behave like exponentional functions. The term relating to disturbance forces the frequency to decay, whereas, the summation term helps the frequency to recover. At a certain time, the sum of both the terms attain a minimum value, the frequency will be minimum at this time. The behaviour of both the functions is shown in Fig. 2.5.

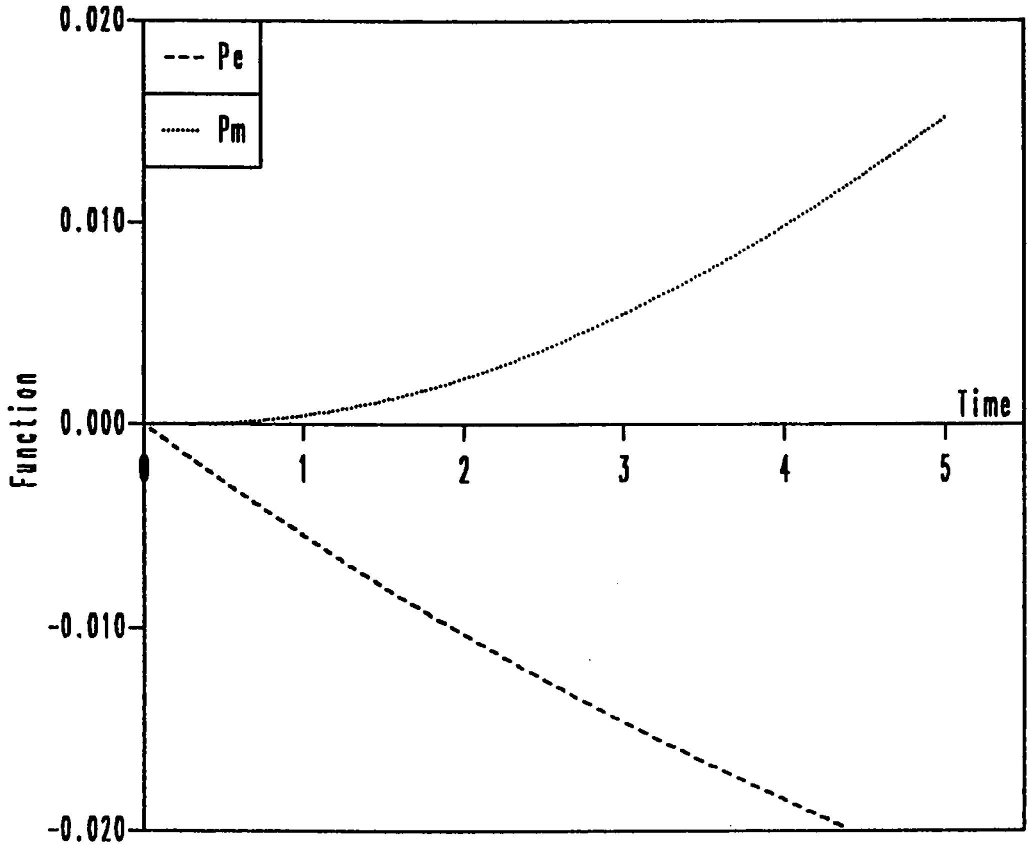

Fig. 2.5: The behaviour of two functions which produce frequency deviation.

2.3.1 Determination of Valve Model Parameter

The approximate model for the valve motion given by Eq. 2.1 and Eq. 2.2 contain only one unknown parameter ξ_k for each power plant. To obtain this parameter, each power plant is simulated by numerically integrating the differential equations obtained from the closed loop model of Fig. 2.1. The magnitude of disturbance is selected so that there is no valve rate limiting. A least square algorithm is used to estimate the unknown parameter ξ_k .

2.4 PREDICTION OF MINIMUM FREQUENCY

It is not possible to obtain an explicit expression for the maximum frequency deviation and its time of occurance. However, the minimum frequency and its time of occurance can be obtained using a search routine. Newton-Raphson method is used to estimate or calculate the minimum frequency and its time of occurance. The minimum frequency will occur when

$$\frac{d}{dt}\omega(t)\Big|_{t=t_{min}} = 0$$

where

$$\omega(t) = 1 + \Delta\omega(t)$$

So,

$$\frac{d}{dt}\omega(t) \equiv \frac{d}{dt}\,\Delta\omega(t) = 0$$

The parameters of the generators, governor and turbine are given in Appendix A.

2.5 GENERATOR MECHANICAL POWER AS A FUNCTION OF TIME

The generator mechanical power is not directly available in the frequency prediction formula. The frequency prediction formula is a combination of two main functions; one relating to mechanical power (say $\Delta\omega_1$) and other relating to electrical power (say $\Delta\omega_2$). The generator mechanical power is calculated from $\Delta\omega_1$:

$$\Delta\omega_1 = \frac{\sum \Delta P_{m,k}}{2H_T s + D_T}$$

or

$$\Delta\omega_{1,k} = \frac{\Delta P_{m,k}}{2H_T s + D_T}$$

$$\Delta P_{m,k} = 2H_T \Delta\dot{\omega}_{1,k} + D_T \Delta\omega_{1,k} \tag{2.9}$$

where

$$\Delta\dot{\omega}_{1,k} = \frac{d}{dt}[\Delta\omega_{1,k}]$$

So

$$\Delta P_{m,k}(t) = R_{v,k} \Bigg[C_{o,k}\, D_T\, [\, U(t) - U(t-T_{d,k})\,]$$

$$+ C_{1,k}[(2H_T + D_T t)\, U(t) - (2H_T + (t-T_{d,k})D_T)\, U(t-T_{d,k})]$$

$$+ \sum_{j=2}^{4} C_{j,k}\, (\, D_T - 2H_T\, a_{j,k}\,) \Big[e^{-a_{j,k}t}\, U(t)$$

$$- e^{-a_{j,k}(t-T_{d,k})}\, U(t-T_{d,k}) \Big] \Bigg] \qquad (2.10)$$

Hence, the mechanical power output of the k^{th} power plant can be calculated from equation (2.10). The total mechanical power of the system is given by the following equation:

$$\Delta P_{m,T} = \sum_{k=1}^{NG} \Delta P_{m,k}(t) \qquad (2.11)$$

The comparison of the mechanical powers calculated from frequency prediction formula and simulation is shown in Fig. 2.6. The percentage error between two mechanical powers is small in time range of interest. The error increases after occurance of minimum frequency, because the valve remains at its limit in frequency prediction. But, in simulation, the valve settle at a point below its limit.

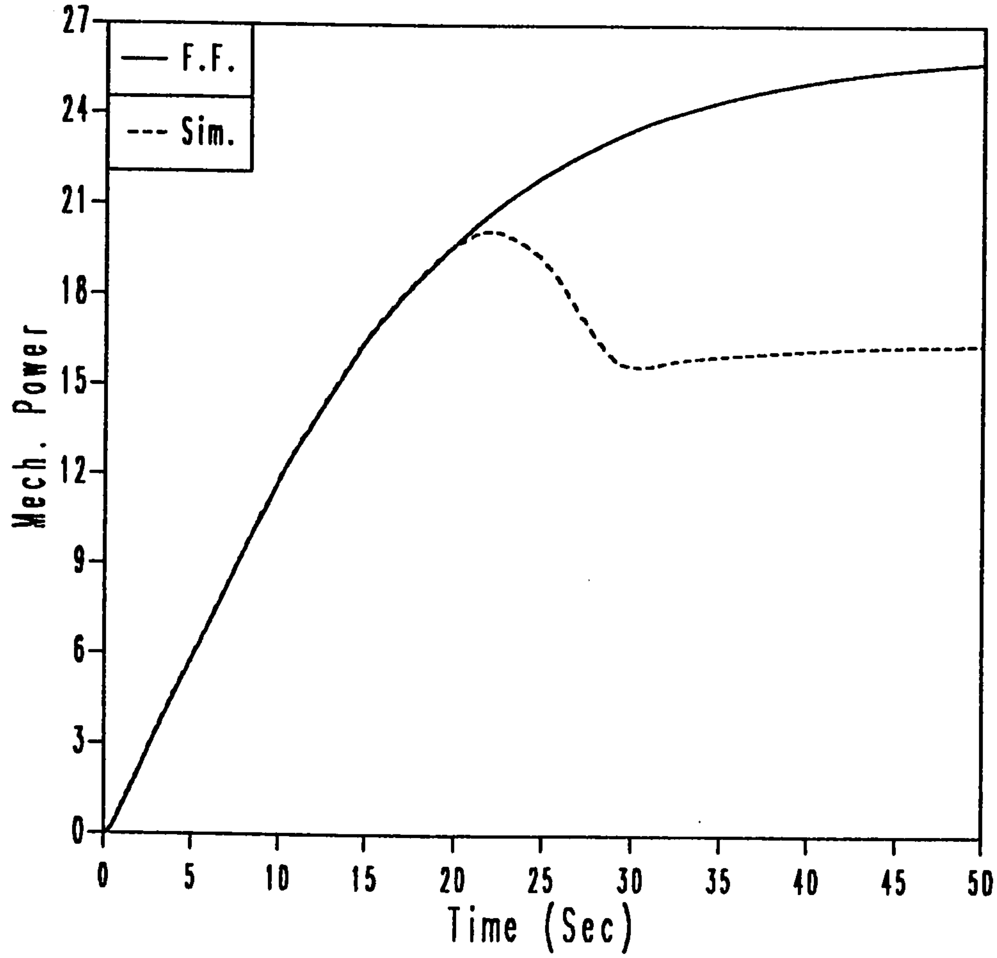

Fig. 2.6: The comparision of two mechanical powers for 20 % load disturbance.

CHAPTER 3

LOAD SHEDDING

CHAPTER 3

LOAD SHEDDING

3.1 INTRODUCTION

Most modern generators are designed so that there will be no resonance problem in frequency range of 58-60 Hz, operation below this range may lead to the development of excessive stresses which may initiate blading fatigue cracks. Turbine blading system damage, resulting from under-frequency condition, could lead to a prolonged outage of critically needed generating unit. In order to avoid this, load shedding is undertaken after all reserve capacities are used up. The load is dropped temporarily in order to maintain a load-to-generation balance during a system disturbance.

3.2 PREDICTION OF TIME OF LOAD SHEDDING

The condition for load to be shed at a certain time is given by:

$$\Delta\omega(t)\Big|_{t=t_{\ell s}} = \Delta\omega_{\ell s} \tag{3.1}$$

where

$\Delta\omega_{\ell s}$ is the frequency deviation at which load is shed

$t_{\ell s}$ is the time at which load is shed after a disturbance.

The Newton-Raphson method is applied to frequency prediction formula given by Eq. 2.7 to predict the time $t_{\ell s}$ at which load is shed.

3.3 MODIFICATION IN FREQUENCY PREDICTION FORMULA FOR LOAD SHEDDING

Whenever load is shed, the load-generation imbalance reduces as compared to initial disturbance. If ΔP_L^0 is the initial disturbance, $\Delta P_{\ell s}$ is the load shed then the new load-to-generation imbalance ΔP_L^n can be given as:

$$\Delta P_L^n = \Delta P_L^0 - \Delta P_{\ell s} \tag{3.2}$$

The term corresponding to mechanical power has one variable depending on the system initial disturbance i.e. rate of change of valve area. Once valve is opened, it will remain open until minimum frequency has occured. So, the rate of change of valve area will not change with a change in load-to-generation imbalance. Hence, only the last term in the frequency prediction formula corresponding to electrical power is modified which is proportional to ΔP_L^n. The term which needs to be modified is an exponential function given by:

$$F_6 = \frac{\Delta P_L^0}{D_T}\left[1 - e^{-bt} \right] \tag{3.3}$$

where

$$b = \frac{D_T}{2H_T}$$

Assume that at $t = t_{\ell s}$ an amount of load $\Delta P_{\ell s}$ is shed. The term is modified as

$$F_6^n = \left[\frac{\Delta P_L^0 - \Delta P_{\ell s}}{D_T} - F_6(t_{\ell s}) \right]\left[1 - e^{-b(t-t_{\ell s})} \right] + F_6(t_{\ell s})$$

$$F_6^n = \frac{\Delta P_L^0}{D_T}\left[1 - e^{-bt}\right] - \frac{\Delta P_{\ell s}}{D_T}\left[1 - e^{-b(t-t_{\ell s})}\right] U(t-t_{\ell s}) \tag{3.4}$$

Since the relays operate with a certain delay time, this delay time is included in the frequency prediction formula. The equation (3.4) with delay time is written as:

$$F_6^n = \frac{\Delta P_L^0}{D_T}\left[1-e^{-bt}\right] - \frac{\Delta P_{\ell s}}{D_T}\left[1-e^{-b(t-t_{\ell s}-t_{d\ell})}\right] U(t-t_{\ell s}-t_{d\ell}) \tag{3.5}$$

Where

$t_{d\ell}$ = Delay time of relay

The frequency prediction formula after load shedding is given by:

$$\Delta\omega(t) = \sum_{k=1}^{NG} R_{v,k} \Bigg[C_{o,k}U(t) + C_{1,k}[t\ U(t) - (t-T_{d,k})U(t-T_{d,k})]$$

$$+ \sum_{j=2}^{4} C_{j,k} [e^{-a_{j,k}t}U(t) - e^{-a_{j,k}(t-T_{d,k})}U(t-T_{d,k})]$$

$$+ C_{5,k} [e^{-bt}\ U(t) - e^{-b(t-T_{d,k})}\ U(t-T_{d,k})] \Bigg]$$

$$- \frac{\Delta P_L^0}{D_T}\left[1-e^{-bt}\right] + \frac{\Delta P_{\ell s}}{D_T}\left[1-e^{-b(t-t_{\ell s}-t_{d\ell})}\right] U(t-t_{\ell s}-t_{d\ell}) \quad (3.6)$$

The term relating to initial electric power disturbance ΔP_L^0 forced the frequency to decay. When some load $\Delta P_{\ell s}$ is shed, an exponential function with a maximum amplitude of $\frac{\Delta P_{\ell s}}{D_T}$ in addition to the mechanical power helps frequency to recover quickly.

3.4 LINEAR TYPE LOAD SHED SCHEMES

In common practice, fixed amount of loads are shed in blocks at different frequency set-points without considering the size of disturbance. These types of load shed schemes are known as linear load shedding schemes. The criteria used to design linear type load shed schemes in given in appendix B.

3.4.1 Evaluation

A seven step load shed scheme [9] is selected for testing and comparison. The design criteria used to establish this load shedding scheme were

a) to return the frequency to above 58.0 Hz within 12 seconds

b) not to let the frequency go above 62.0 Hz after load shedding occurs.

This scheme is shown in Table 3.1. This scheme is implemented with time delay and without time delay. This scheme is tested on 39 bus, 10 generator system. The results of frequency prediction formula were compared with simulation.

Set Point Designation	Frequency Hz	Time Delay Sec.	% age Load to be Shed	Cumulative % Load Shed
1	59.7	0.28	9	9
2	59.4	0.28	7	16
3	59.1	0.28	7	23
4	58.8	0.28	6	29
5	58.5	0.28	5	34
6	58.0	0.28	7	41
7	59.7	12.00	3	44

Table 3.1: Load Shedding Scheme used for tests

3.5 RATE OF CHANGE OF FREQUENCY DEPENDENCE LOAD SHED SCHEME

The load shedding schemes in most developed and developing countries are still using under frequency relays which operates at certain frequency set-points. These type of schemes provide slower recovery for a severe disturbances.

An obvious alternative method is to design the frequency relay not to function with the change of frequency but instead with the rate of change of frequency. This enables shedding a load in direct proportion to the disturbance and inversely to the system inertia [13].

However, due to system switching operations and load/frequency responses, the application of the rate of change of frequency techniques is still under study and rarely utilized. An alternate way is to develop a load shed scheme using rate of change of frequency operating at certain frequency setpoints.

A rate of change of frequency load shed scheme is designed using the same criteria and setpoints by [9]. In this scheme, it is proposed to shed the load in the three stages at a setpoint according to rate of change of frequency. The rate of change of frequency load shed scheme is shown in Table 3.2.

Set point	Frequency Hz	Time Delay Sec.	% Load to be Shed	Rate of change of frequency	Cumulative % Load Shed
1	59.7	0.28	4	≥ 0.30	4
		0.28	5	≥ 0.75	9
		0.28	6	≥ 1.50	15
2	59.4	0.28	6	≥ 0.30	21
		0.28	4	≥ 0.75	25
		0.28	3	≥ 1.50	28
3	59.1	0.28	4	≥ 0.30	32
		0.28	3	≥ 0.75	35
		0.28	2	≥ 1.50	37
4	58.8	0.28	2	≥ 0.05	39
		0.28	2	≥ 0.15	41
		0.28	3	≥ 0.30	44
5	58.5	0.28	2	≥ 0.05	46
		0.28	2	≥ 0.15	48
6	58.0	0.28	2	≥ 0.05	50
		0.28	2	≥ 0.15	52
7	59.7	12.00	3	≥ 0.05	55

Table 3.2: Rate of Change of Frequency Dependence Load Shed Scheme

CHAPTER 4

DYNAMIC CONTINGENCY ANALYSIS

CHAPTER 4

DYNAMIC CONTINGENCY ANALYSIS

Present day contingency analysis in modern interconnected power system is normally based on steady state network solutions, i.e. load flow results. In these studies, the transmission network's characteristics are analyzed under various contingencies such as line or generator outages. Detailed dynamic contingency analysis of electric power systems are of great practical significance since one relies today more and more on dynamics instead of static contingency analysis. The extension of contingency analysis of large power networks to the transient behaviour of the system operating states, known as dynamic contingency analysis, is needed in order to guarantee a secure system operation.

4.1 DEVELOPMENT OF DYNAMIC LOAD FLOW

For the study of transient behaviour of the system quantities such as, real & reactive power generations, bus voltages, line flows, etc., there is a need to develop a dynamic load flow program. The real power generation as a function of time is fed to load flow to produce dynamic load flow which can compute system quantities as a function of time following a contingency.

This part deals with the combination of a fast decoupled load flow and frequency prediction formula to produce a dynamic load flow.

4.1.1 Generator Real Power as a function of time

The average system frequency deviation is given by:

$$\Delta\omega = \frac{\Delta P_{m,T} - \Delta P_{e,T}}{2H_T s + D_T} \tag{4.1}$$

or

$$\sum \Delta P_{m,k} - \sum \Delta P_{e,k} = 2\sum H_k \Delta\dot{\omega} + \sum D_k \Delta\omega$$

$$\Delta P_{e,k} = \Delta P_{m,k} - [\, 2H_k \Delta\dot{\omega} + D_k \Delta\omega \,] \tag{4.2}$$

where

$$\Delta\dot{\omega} = \frac{d}{dt}[\Delta\omega(t)]$$

$$P_{e,k} = P^{0}_{e,k} + \Delta P_{e,k} \tag{4.3}$$

The change in generator real power can be calculated from equation (4.2). The only unknown term is $\Delta P_{m,k}$ which is obtained from equation (2.10).

$$\Delta P_{e,k}(t) = R_{v,k} \Big[C_{o,k}\, D_T\, [\, U(t) - U(t-T_{d,k})\,]$$

$$+ C_{1,k}[\, (2H_T + D_T t)\ U(t) - (2H_T T + (t-T_{d,k})D_T)U(t-T_{d,k})]$$

$$+ \sum_{j=2}^{4} C_{j,k}\, (\, D_T - 2H_T\, a_{j,k}\,) \Big[\, e^{-a_{j,k}t}\, U(t)$$

$$- e^{-a_{j,k}(t-T_{d,k})}\ U(t-T_{d,k})\, \Big] \Big]$$

$$- \sum_{i=1}^{NG} R_{v,i} \Big[C_{o,i}\, D_i\, (\, U(t) - U(t-T_{d,i})\,)$$

$$+ C_{1,i} \Big[(2H_i + D_i\ t)\ U(t) - (2H_i + D_i(t-T_{d,i}))\ U(t-T_{d,i}) \Big]$$

$$+ \sum_{j=1}^{4} C_{j,i} \Big[(D_i - 2\ a_{j,i}\ H_i)\, [\, e^{-a_{j,i}t} U(t) - e^{-a_{j,i}(t-T_{d,i})}\ U(t-T_{d,i})\,]$$

$$+ (D_i - 2bH_i)[\, e^{-a_{j,i}t}\ U(t) - e^{-a_{j,i}(t-T_{d,i})}\ U(t-T_{d,i})] \Big] \Big]$$

$$- \left[\frac{D_k}{D_T}\, \Delta P_L - \left(\frac{D_k - 2bH_k}{D_T}\right) \Delta P_L\ e^{-bt} \right] \qquad (4.4)$$

4.1.2 Formulation of Dynamic Load Flow

The generator real power calculated from Equation (4.3) for a generator outage/load contingency is fed to the fast decoupled load flow program during time range of interest. The load flow computes the following:

(a) Bus angle $\theta(t)$

(b) Bus voltages $v(t)$

(c) Line flows $P_{jk}(t)$

(d) Generator reactive power $Q_{ek}(t)$

The block diagram representing the formulation of the dynamic load flow is shown in Fig. 4.1. The results of the dynamic load flow are compared with the results of simulation. The results are discussed in the later chapter.

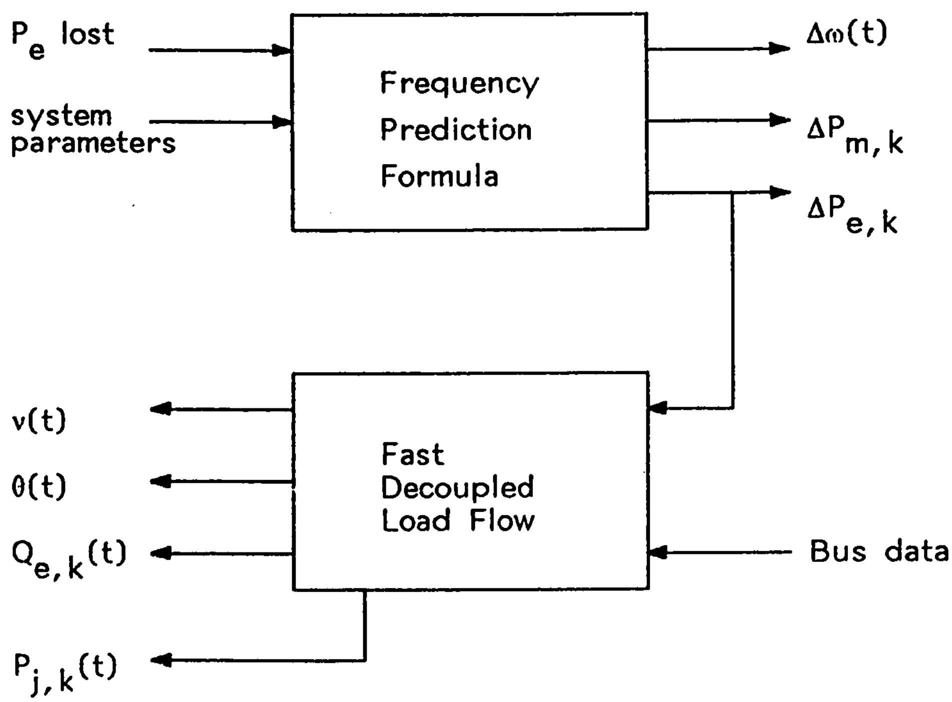

Fig. 4.1 Block diagram of dynamic load flow

4.2 DYNAMIC CONTINGENCY ANALYSIS

Dynamic contingency analysis is based on the assumption that the transient stability is not violated. Steady state contingency analysis of electric power system is not enough because it ignores the transient aspect of the problem. The types of disturbances considered in this thesis to perform dynamic contingency analysis are:

a) Generator Outages
b) Sudden change of load

The study of typical frequency, real and reactive power flows on strong tie lines, bus voltage and bus angle after large disturbances leads to several observations. Under the assumption that transient stability limit is maintained, there are typically two time ranges:

1) Medium term power system dynamics in the time range of $0 \le t \le 60$ sec.
2) Long term power system dynamics in the time range of $0 \le t \le 1000$ sec.

Ten to twenty seconds after a load disturbance has occured the secondary control, i.e. load frequency control, becomes effective and frequency deviation begins to decrease. The slow speed dynamics cover the time range up to several minutes. Hence, the effects of the thermodynamic part of the power stations with inherent large time constants become apparent. The boiler dynamics with large time constants are neglected, hence, this thesis deals with the time range of $0 \leq t \leq 20$ sec which belongs to the first time range. Only, generator outage contingencies were considered for dynamic contingency analysis.

4.2.1 Performance Indices

The system performance index is a measure that can be used to evaluate the relative severity of a contingency. System performance indices are not unique and take on different forms depending on the parameter that are of most importance to engineer. In selecting a performance, physical properties of the system should be taken into consideration. The most common form of the system performance indicies give a measure of the deviation from rated values of system variables such as line flows, bus voltages, bus power injections, etc. However, no system performance index reported in the literature addresses frequency deviation, so, there is need to define performance indices based on maximum frequency deviation, amount of load shed, etc.

1) Frequency Deviation Performance Indices

a) Base on Disturbance Size:

A performance index based on maximum frequency deviation, disturbance size and margin-to-deficiency ratio is defined as:

$$PI_f = \frac{(60 - f_{min})\, \Delta P_L}{(MDR - 1)}$$

or

$$PI_f = \frac{\Delta f_{max}\, \Delta P_L}{(MDR - 1)} \qquad (4.7)$$

where

f_{min} = Minimum frequency

ΔP_L = Initial disturbance

MDR = Margin-to-deficiency ratio

$\Delta f_{max} = 60 - f_{min}$

The initial disturbance ΔP_L can be a change in load or loss of a block of generating units or major tie lines.

$$\Delta P_L = \sum_{k \in \Omega_L} P^0_{gen,k}$$

Ω_L = set of loss of generating units

The above performance index is defined on frequency deviation and disturbance because the severity is strongly dependent on the maximum frequency deviation and size of disturbance. The disturbance is more severe as margin to deficiency ratio approaches 1, so, it is also included in the performance index.

b) Based on Load Shed:

A performance index, shown in equation (4.8), is defined based on maximum frequency deviation after load shed, amount of load shed, margin-to-deficiency ratio, etc.

$$PI_{\ell s} = \frac{(60 - f_{min,\ell s})\,\Delta P_{\ell s}}{(MDR - 1)} \tag{4.8}$$

where

$f_{min,\ell s}$ = Minimum frequency after load shed

$\Delta P_{\ell s}$ = Amount of load shed

The above performance index is defined on maximum frequency deviation with load shedding and amount of load shed because load shed amount is directly proportional to the severity.

2) Real Power Performance Index

The real power performance index, shown in equation (4.9), gives a measure of line MW overloads, is used for comparison with frequency performance indices [14].

$$PI_{MW} = \sum_{\alpha} W_p \left[\frac{P_\ell}{P_\ell^{max}} \right]^2 \qquad (4.9)$$

where

W_p = Real power weighting factor

P_ℓ = MW flow in line ℓ

P_ℓ^{max} = MW capacity of limit

α = Set of overloaded lines

The weighting factor W_p can be regarded as tuning parameter and it is selected on the experience with system and on the relative importance placed on the various limit violation. In this thesis, W_p is set to 1.

4.2.2 Contingency Ranking

The on-line contingency analysis of a power system requires the evaluation of the effects of all possible contingencies on the system. For a power system of average size, it is generally agreed that the analysis of several hundred contingencies is usually adequate. Full AC analysis using a power flow for several hundred cases presents a major computational burden. Since only a few of the contingencies are security risks at any given time, the contingencies should be ranked and more severe contingencies should be selected. The main reason for having contingency selection in analyzing on-line security is to minimize the computational requirements. However, this has to be balanced against the accuracy of the total security analysis.

The full first iteration of the fast decoupled power flow is used to calculate the real power performance index for every outage. The frequency performance indicies are calculated from the results of frequency prediction formula for every outage. Outages are then ranked on the basis of their corresponding performance indicies.

Once the ranking of contingencies is done according to their severity, the more severe cases may be analyzed further for more details with more accuracy.

CHAPTER 5

RESULTS AND DISCUSSIONS

CHAPTER 5

RESULTS AND DISCUSSIONS

5.1 INTRODUCTION

The frequency prediction formula combined with the Fast Decoupled Power Flow program is tested on IEEE 39-bus system. The above stated system is also used for average system frequency simulation. In this chapter, the results obtained from the study on 39-bus system are presented.

5.2 DESCRIPTION OF SAMPLE POWER SYSTEM

The IEEE 39-bus sample power system is typical and represents the 345 KV system of New-England area. This power system is made up of 46 branches (lines), 39 buses, 10 generators and 12 off-nominal transformers. The loads are connected to 19 buses and 3 switchable capacitors are added to buses 15, 33 and 37. The system bus data, line data and the base-case load flow solution based on 100 MVA base are shown in Appendix C. The single line diagram of IEEE 39-bus system is shown in Fig. 5.1. The loading condition of the system shown in Appendix C is considered as base-case.

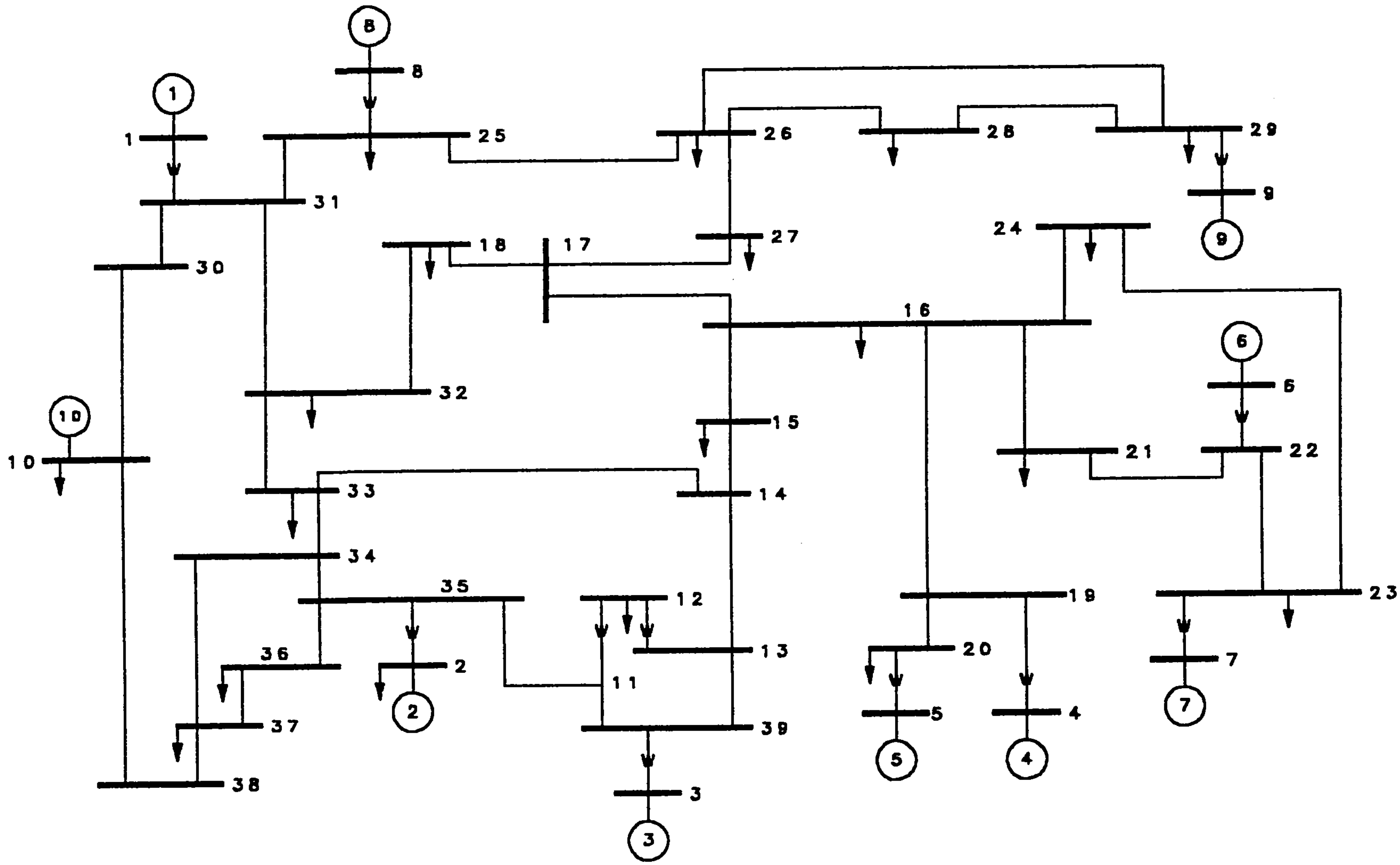

Fig. 5.1: Single Line Diagram of IEEE 39-Bus System

5.3 COMPARISON OF FREQUENCY PREDICTION FORMULA WITH SIMULATION

Case 1: No Load Shedding

Several load disturbances were applied on the test system for different values of margin-to-deficiency ratios. Some results of minimum frequency and its time of occurrence for different disturbances are shown in Table 5.1. System conditions were altered according to disturbance size and margin-to-deficiency ratio. Some of these conditions are given in Appendix D. For this test, there was no load shedding. Figure 5.2 and Figure 5.3 show the variation in frequency for 5% change in load and for 1.2 and 4.0 margin-to-deficiency ratio's respectively.

For the case shown in Fig. 5.2, the percentage error between the minimum frequency using simulation and that obtained from frequency prediction formula is about 1.03 %. For the case shown in Fig. 5.3, the percentage error is about 2.99 %.

The percentage error between two minimum frequencies is plotted against frequency deviation for different disturbance sizes. The behaviour of percentage error is shown in Fig. 5.4. The percentage error is high for small disturbances (1-2 %) and for large margin-to-deficiency ratio's > 3 because the valve area is opened at its limit in frequency prediction formulation and the valve not even reached its valve area limit in simulation for these

MDR	$\Delta P_{L\%}$	f_{min} Hz			t_{min} Sec.		
		F.F.	Sim.	%error	F.F.	Sim.	%error
1.02	1.0	59.789	59.784	2.32	10.304	10.310	0.06
	2.0	59.576	59.568	1.85	10.275	10.280	0.05
	5.0	58.898	58.890	0.72	10.239	10.240	0.01
	10.0	57.621	57.614	0.29	10.126	10.130	0.04
	15.0	56.155	56.149	0.16	10.120	10.130	0.10
1.05	1.0	59.796	59.791	2.39	9.954	9.960	0.06
	2.0	59.588	59.581	1.97	9.944	9.950	0.06
	5.0	58.925	58.916	0.83	9.935	9.940	0.05
	10.0	57.661	57.654	0.30	9.841	9.850	0.09
	15.0	56.202	56.196	0.16	9.821	9.820	0.01
1.20	1.0	59.821	59.816	2.72	8.601	8.600	0.01
	2.0	59.640	59.631	2.44	8.571	8.570	0.01
	5.0	59.037	59.027	1.03	8.635	8.640	0.06
	10.0	57.825	57.817	0.37	8.585	8.590	0.06
	15.0	56.365	56.360	0.18	8.810	8.810	0.00
1.50	1.0	59.857	59.849	5.30	6.718	6.720	0.03
	2.0	59.715	59.702	4.36	6.618	6.620	0.03
	5.0	59.201	59.191	1.24	6.482	6.490	0.12
	10.0	58.012	58.001	0.55	6.975	6.980	0.07
	15.0	56.555	56.547	0.23	7.746	7.750	0.05
2.00	1.0	59.896	59.879	14.05	4.134	4.150	0.39
	2.0	59.783	59.760	10.65	4.139	4.160	0.50
	5.0	59.314	59.298	2.28	4.608	4.620	0.26
	10.0	58.145	58.134	0.59	6.016	6.010	0.10
	15.0	56.720	56.713	0.24	7.192	7.190	0.03
3.00	1.0	59.918	59.896	21.16	3.619	3.620	0.03
	2.0	59.818	59.792	13.20	2.700	2.680	0.75
	5.0	59.382	59.364	2.83	3.780	3.800	0.53
	10.0	58.279	58.266	0.75	5.420	5.430	0.18
4.00	1.0	59.923	59.900	23.01	2.090	2.089	0.05
	2.0	59.826	59.801	14.00	2.412	2.402	0.42
	5.0	59.416	59.398	2.99	3.495	3.530	0.99
	10.0	58.350	58.337	0.78	5.027	5.030	0.06

Table 5.1: Minimum frequency and its time of occurance for different values of MDR and disturbances.

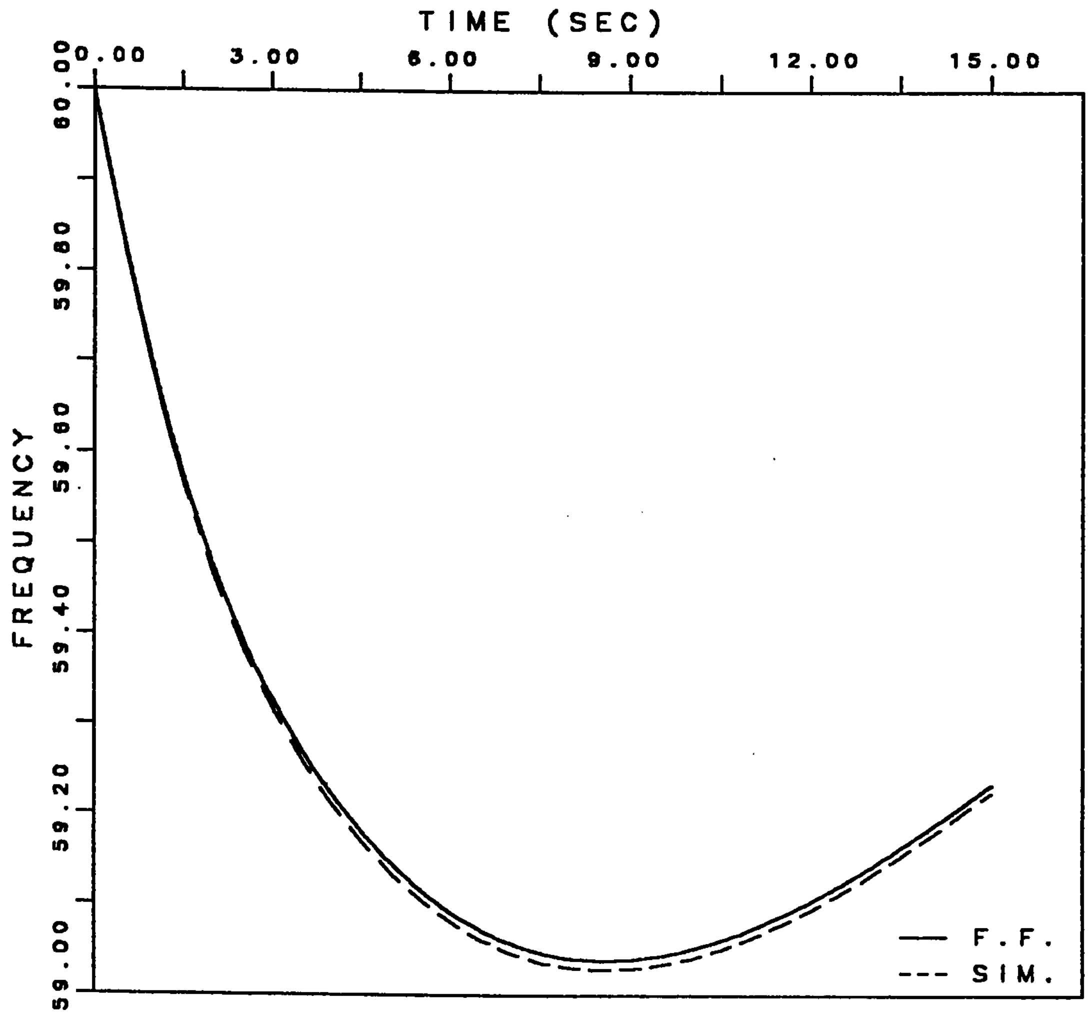

Fig. 5.2: Comparison of two frequencies for a disturbance of 5.0% and MDR=1.2.

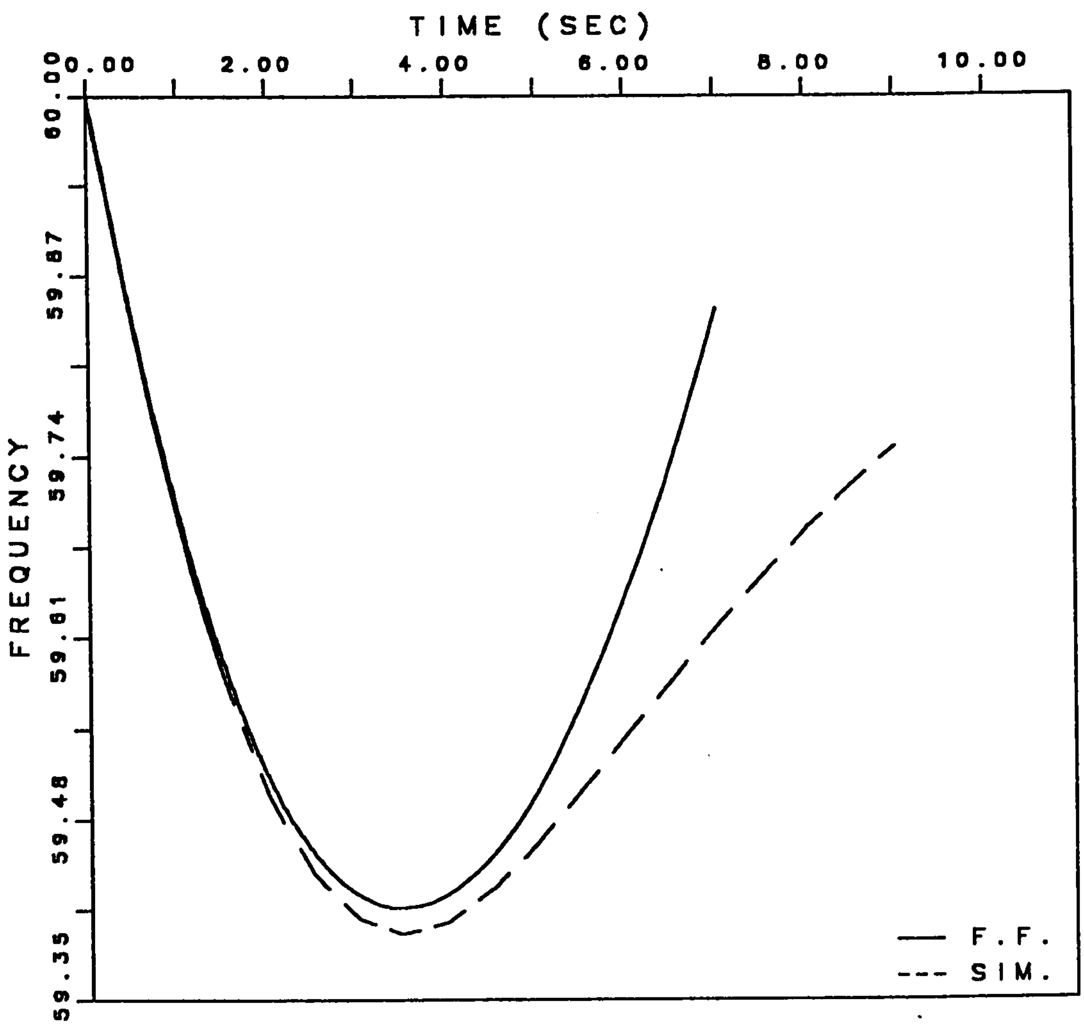

Fig. 5.3: Average system frequency transient for a 5.0% change in load and MDR=4.0.

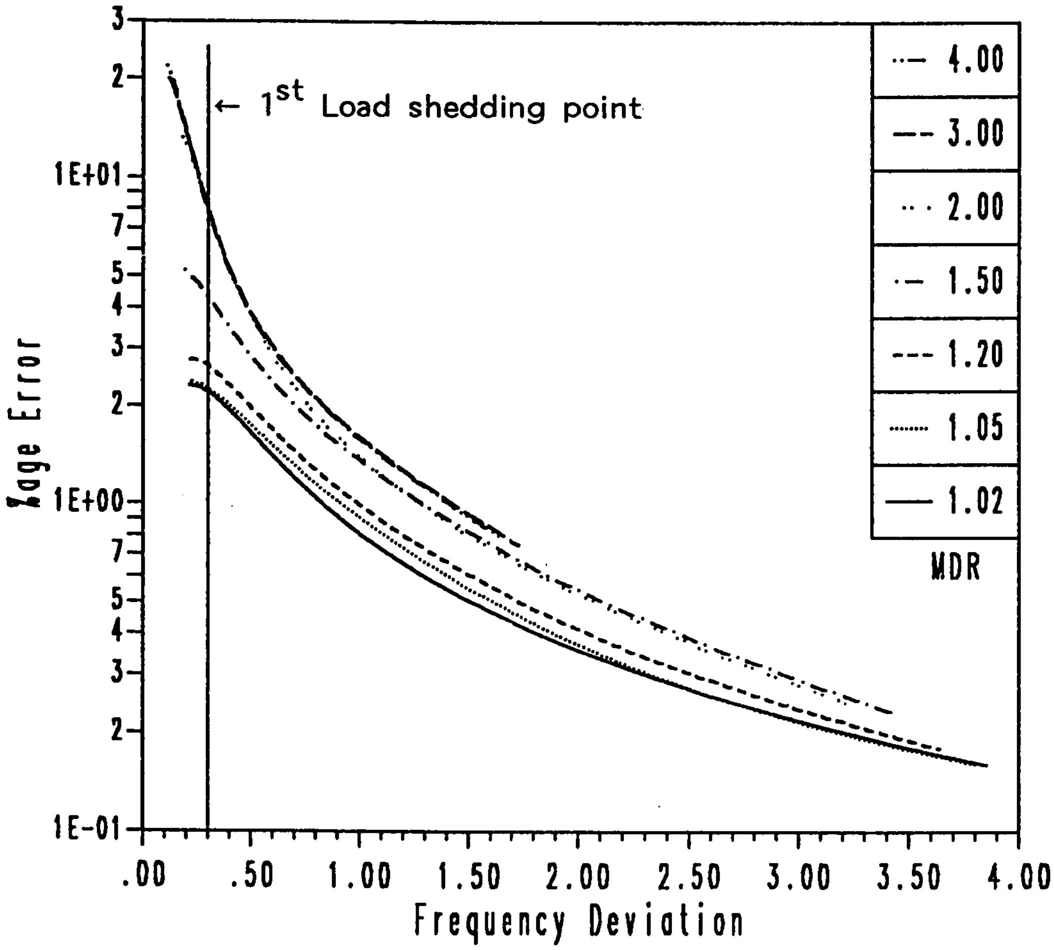

Fig. 5.4: Percentage error for different disturbances and margin to deficiency ratios (MDR's).

small disturbances. Whereas, the percentage error is small for large disturbances (more than 5 %) and for low margin-to-deficiency ratio's which is the range of interest.

Table 5.2 shows the comparison of minimum frequency and its time of occurrence for different values of disturbances applied on base-case of test system. The comparison of minimum frequency and its time occurrence for generator outage cases is shown in Table 5.3.

Fig. 5.5 shows the comparison of two frequencies for a disturbance of 7.4 p.u. and 3.53 margin-to-deficiency ratio (disturbance applied on base-case condition). The percentage error between two frequencies is about 1.01. These errors are mainly due to the fact that the valve is open at its maximum limit after t_{min} for frequency prediction formula and valve area begins to decrease for simulation. Also, in frequency prediction formula, the governor valve remains open after reaching its limit, but, in simulation some of the governor valves may not even reach their valve area limit.

The results of the study show that the maximum percentage error, when prediction is compared with numerical integration results, is of the order of 23.01 for margin-to-deficiency ratio 4.0 and 1% disturbance. Actually, the difference between two frequencies is 0.023 Hz. The percentage error is high for small

MDR	ΔP_L %	f_{min} Hz			t_{min} Sec.		
		F.F.	Sim.	%error	F.F.	Sim.	%error
1.02	29.1	51.216	51.214	0.023	10.961	10.955	0.055
1.20	24.7	53.058	53.044	0.050	9.874	9.870	0.233
1.50	19.8	54.997	54.991	0.116	8.617	8.610	0.081
2.00	14.8	56.771	56.762	0.262	7.157	7.155	0.028
3.00	9.9	58.306	58.293	0.732	5.408	5.415	0.129
4.00	7.4	58.945	58.929	1.495	4.310	4.320	0.231

Table 5.2: Minimum frequency and its time of occurance for different values of MDR and disturbances (for base case).

Outage Case	MDR	ΔP_L pu	f_{min} Hz F.F.	f_{min} Hz Sim.	f_{min} Hz %error	t_{min} Sec. F.F.	t_{min} Sec. Sim.	t_{min} Sec. %error
1	6.94	2.7	59.688	59.684	1.38	2.563	2.58	0.66
2	4.51	5.6	59.047	59.030	1.76	4.058	4.07	0.29
3	3.91	6.5	58.780	58.770	0.83	4.522	4.53	0.18
4	3.56	6.3	58.803	58.786	1.38	4.819	4.82	0.02
5	4.97	5.1	59.201	59.192	1.11	3.805	3.81	0.13
6	3.79	6.5	58.740	58.726	1.11	4.772	4.77	0.04
7	4.64	5.6	59.094	59.083	1.22	3.873	3.89	0.44
8	4.80	5.4	59.150	59.135	1.71	3.795	3.80	0.13
9	3.11	8.3	58.175	58.172	0.14	5.455	5.45	0.09
10	1.61	10.0	56.765	56.762	0.10	7.530	7.53	0.00
1, 2	2.13	8.3	57.798	57.788	0.45	6.205	6.19	0.24
1, 3	1.93	9.2	57.395	57.386	0.34	6.595	6.59	0.08
1, 4	1.64	9.0	57.334	57.325	0.33	7.408	7.39	0.24
1, 5	2.26	7.7	58.070	58.060	0.51	5.946	5.94	0.10
1, 6	1.85	9.2	57.299	57.292	0.27	6.876	6.87	0.09
1, 7	2.21	8.3	57.920	57.906	0.68	5.960	5.95	0.08
1, 8	2.26	8.1	57.990	57.980	0.53	5.914	5.91	0.07
1, 9	1.65	11.0	56.515	56.507	0.22	7.467	7.47	0.04
1,10	0.66	12.7	54.097	54.094	0.04	11.767	11.76	0.06
2, 9	1.80	13.9	55.213	55.206	0.14	8.129	8.13	0.01
2,10	0.98	15.6	52.598	52.595	0.04	10.751	10.74	0.10
3, 9	1.69	14.8	54.700	54.693	0.12	8.399	8.39	0.11
3,10	0.93	16.5	51.943	51.940	0.03	10.951	10.94	0.10
4, 9	1.51	14.6	54.547	54.541	0.12	9.174	9.17	0.04
4,10	0.76	16.3	51.510	51.507	0.03	12.466	12.46	0.05
5, 9	1.86	13.4	55.653	55.646	0.16	7.822	7.82	0.03
5,10	1.01	15.1	53.307	53.304	0.04	10.267	10.25	0.17
6, 9	1.64	14.8	54.563	54.557	0.11	8.637	8.63	0.08
6,10	0.89	16.5	51.717	51.714	0.03	11.332	11.33	0.02
7, 9	1.84	13.9	55.426	55.419	0.16	7.896	7.89	0.08
7,10	1.02	15.6	52.959	52.956	0.05	10.373	10.37	0.03
8, 9	1.87	13.7	55.503	55.495	0.19	7.898	7.89	0.10
8,10	1.03	15.4	53.027	53.024	0.05	10.445	10.44	0.05
9,10	0.86	18.3	50.420	50.417	0.02	11.847	11.84	0.06
8,9,10	0.66	23.7	44.180	44.179	0.00	14.105	14.10	0.04

Table 5.3: Minimum frequency and its time of occurance for outages of generators (no load shedding).

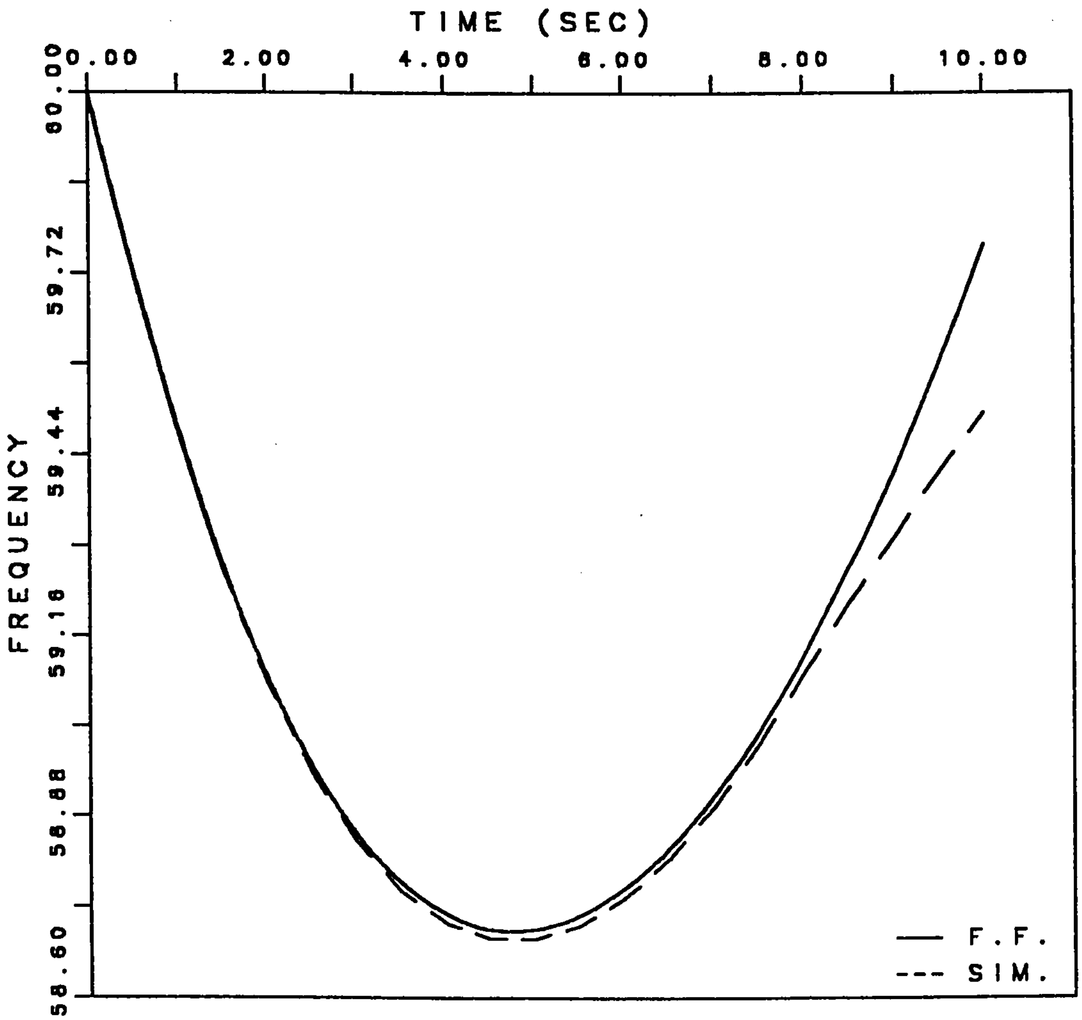

Fig. 5.5: Average system frequency transient for a disturbance of 7.4 p.u. and MDR=3.53.

disturbances (of the order of 1-2%) but is less than 3.0 for large disturbance (5% and more) for MDR ranging from 1.02 to 4.0. The accuracy decreases as margin-to-deficiency ratio increases and disturbance size reduces. However, in practice low MDR and large disturbance cause problem more than higher MDR and small disturbances.

5.3.1 Comparison of Frequency Prediction with Simulation Under Frequency Load Shedding

Case II. Load Shedding Relays Incorporated.

The load shed scheme, shown in Table 3.1 is used for several tests. Table 5.4 shows the comparison of maximum frequency deviation and time of occurrence of minimum frequency after load shedding. The system conditions were altered according to the size of disturbance and margin-to-deficiency ratio. Maximum percentage error is 1.29 for margin-to-deficiency ratio equal to 4.0, actually, the difference between two frequencies is 0.006 Hz.

The comparison of minimum frequency and its time of occurrence after load shedding for different values of disturbance applied on base-case of test system is shown in Table 5.5. The percentage error between minimum frequencies and their time of occurrences for several generator outage contingencies is shown in Table 5.6.

Figure 5.6 shows the average system frequency transient after load shedding (without time delay) for the outage of generator No. 10 (ΔP_L = 10.0 p.u.). Load was shed at two set points (59.7 Hz & 59.4 Hz), amount of load shed was 16% (9.84 p.u.). The comparison of two frequencies for load shed scheme with time delay is shown in Fig. 5.7, the disturbance and load

MDR	ΔP_L %	$\Delta P_{\ell s}$ %	f_{min} Hz F.F.	f_{min} Hz Sim.	f_{min} Hz %error	t_{min} Sec. F.F.	t_{min} Sec. Sim.	t_{min} Sec. %error
1.02	5.0	6.29	59.699	59.698	0.28	0.975	0.970	0.52
	10.0	6.29	59.457	59.455	0.37	3.010	3.030	0.66
	15.0	11.16	59.288	59.286	0.28	2.500	2.490	0.40
1.05	5.0	6.29	59.699	59.698	0.30	0.975	0.970	0.52
	10.0	6.29	59.459	59.456	0.50	3.010	3.020	0.33
	15.0	11.16	59.289	59.287	0.28	2.490	2.480	0.40
1.50	5.0	6.29	59.698	59.699	0.39	0.990	0.980	1.02
	10.0	6.29	59.484	59.480	1.08	2.710	2.720	0.37
	15.0	11.16	59.303	59.300	0.43	2.260	2.270	0.44
2.00	5.0	6.29	59.699	59.700	0.28	0.990	0.970	2.06
	10.0	6.29	59.499	59.493	1.18	2.500	2.510	0.40
	15.0	11.16	59.309	59.306	0.43	2.170	2.180	0.46
3.00	5.0	6.29	59.698	59.698	0.11	1.000	0.980	2.04
	10.0	6.29	59.511	59.505	1.24	2.330	2.340	0.43
	12.0	11.16	59.399	59.396	0.50	1.430	1.420	0.70
4.00	5.0	6.29	59.699	59.699	0.02	1.000	0.980	2.04
	10.0	6.29	59.518	59.512	1.29	2.250	2.260	0.44

Table 5.4: Minimum frequency and its time of occurance after load shedding for different values of MDR and disturbances.

MDR	ΔP_L %	$\Delta P_{\ell s}$ %	f_{min} Hz			t_{min} Sec.		
			F.F.	Sim.	%error	F.F.	Sim.	%error
1.02	29.1	20.90	58.491	58.490	0.07	2.300	2.290	0.44
1.20	24.7	17.84	58.787	58.786	0.12	2.040	2.030	0.49
1.50	19.8	14.15	59.080	59.078	0.20	1.840	1.850	0.54
2.00	14.8	11.16	59.325	59.323	0.30	2.100	2.090	0.48
2.50	11.9	11.16	59.400	59.397	0.46	1.480	1.470	0.68
3.00	9.9	6.29	59.523	59.520	0.56	2.260	2.270	0.44
4.00	7.4	6.29	59.696	59.698	0.63	0.765	0.780	1.92

Table 5.5: Minimum frequency and its time of occurance after load shedding for different values of MDR and disturbances (for base case).

Outage Case	MDR	ΔP_L pu	$\Delta P_{\ell s}$ pu	f_{min} Hz F.F.	f_{min} Sim.	f_{min} %error	t_{min} Sec. F.F.	t_{min} Sim.	t_{min} %error
1	6.94	2.7	5.54	59.700	59.700	0.04	2.05	2.03	0.99
2	4.51	5.6	5.54	59.699	59.697	0.68	0.67	0.66	1.52
3	3.91	6.5	5.54	59.693	59.696	0.80	0.80	0.81	1.23
4	3.56	6.3	5.54	59.692	59.689	0.81	0.66	0.67	1.49
5	4.97	5.1	5.54	59.699	59.699	0.27	0.77	0.76	1.32
6	3.79	6.5	5.54	59.694	59.692	0.73	0.81	0.82	1.22
7	4.64	5.6	5.54	59.697	59.699	0.64	0.69	0.68	1.47
8	4.80	5.4	5.54	59.698	59.700	0.61	0.72	0.71	1.41
9	3.11	8.3	5.54	59.527	59.524	0.63	2.17	2.18	0.46
10	1.61	10.0	9.84	59.399	59.398	0.22	1.11	1.10	0.91
1, 2	2.13	8.3	5.54	59.483	59.479	0.91	2.43	2.42	0.41
1, 3	1.93	9.2	9.84	59.400	59.399	0.20	1.62	1.62	0.00
1, 4	1.64	9.0	9.84	59.399	59.399	0.02	1.86	1.85	0.54
1, 5	2.26	7.7	5.54	59.580	59.578	0.31	1.96	1.97	0.51
1, 6	1.85	9.2	9.84	59.399	59.400	0.08	1.60	1.59	0.63
1, 7	2.21	8.3	5.54	59.502	59.498	0.80	2.26	2.27	0.44
1, 8	2.26	8.1	5.54	59.535	59.531	0.74	2.14	2.15	0.47
1, 9	1.65	11.0	9.84	59.400	59.400	0.03	0.95	0.94	1.06
1,10	0.66	12.7	9.84	59.177	59.176	0.12	2.61	2.60	0.38
2, 9	1.80	13.9	9.84	59.100	59.100	0.04	2.08	2.07	0.48
2,10	0.98	15.6	14.15	59.097	59.096	0.07	0.98	0.97	1.03
3, 9	1.69	14.8	14.15	59.099	59.100	0.12	1.48	1.47	0.68
3,10	0.93	16.5	14.15	59.049	59.048	0.11	1.81	1.80	0.56
4, 9	1.51	14.6	14.15	58.100	58.100	0.01	1.58	1.57	0.64
4,10	0.76	16.3	14.15	59.067	59.068	0.13	1.67	1.67	0.00
5, 9	1.86	13.4	9.84	59.175	59.172	0.33	2.71	2.70	0.37
5,10	1.01	15.1	14.15	59.096	59.099	0.33	1.13	1.12	0.89
6, 9	1.64	14.8	14.15	59.099	59.098	0.15	1.48	1.47	0.68
6,10	0.89	16.5	14.15	59.044	59.043	0.10	1.85	1.84	0.54
7, 9	1.84	13.9	9.84	59.100	59.103	0.33	2.31	2.31	0.00
7,10	1.02	15.6	14.15	59.096	59.096	0.09	1.01	1.00	1.00
8, 9	1.87	13.7	9.84	59.114	59.114	0.04	2.80	2.82	0.71
8,10	1.03	15.4	14.15	59.097	59.096	0.07	1.06	1.05	0.95
9,10	0.86	18.3	17.84	58.798	58.799	0.06	1.76	1.76	0.00
8,9,10	0.66	23.7	20.91	58.457	58.457	0.02	2.00	1.99	0.50

Table 5.6: Minimum frequency and its time of occurance after load shedding for outages of generators.

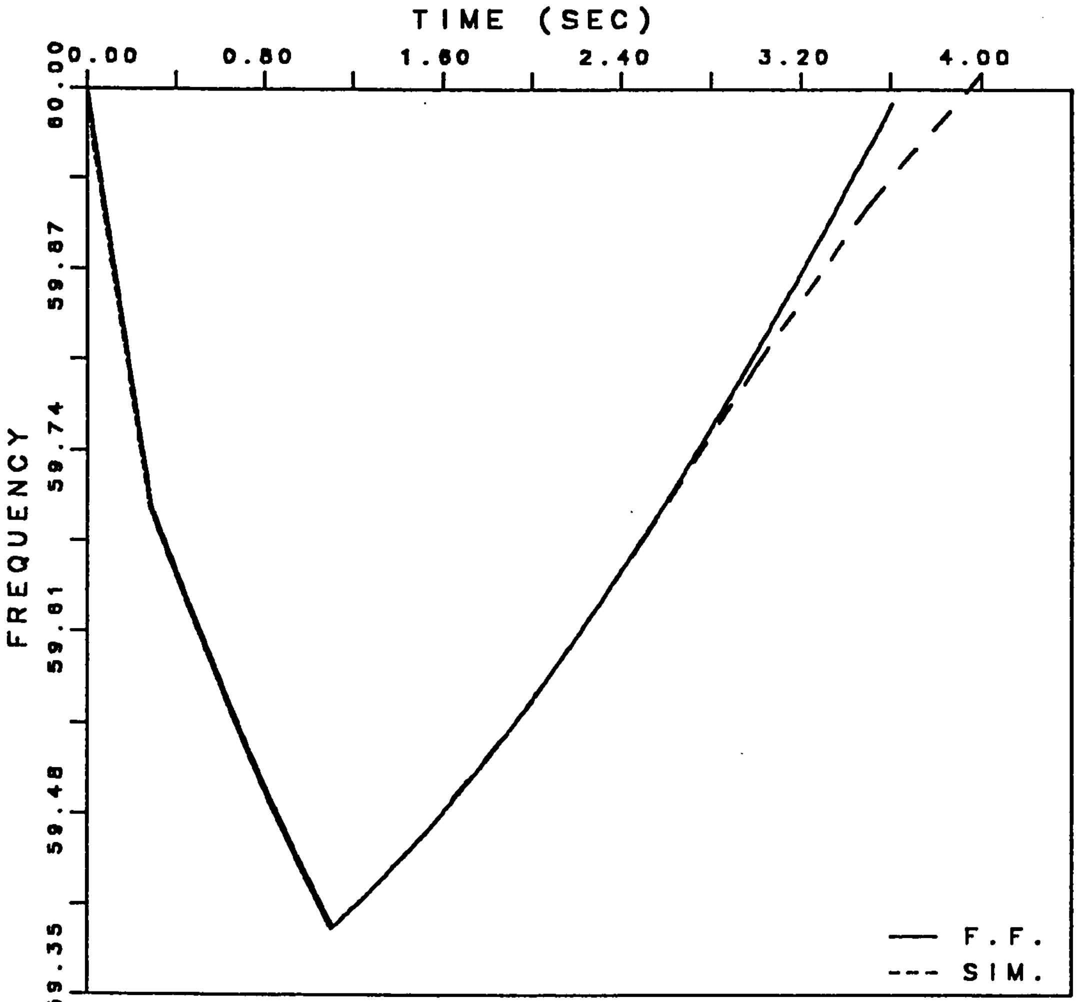

Fig. 5.6: Average system frequency transient after implementation of load shed scheme without time delay (load was shed in two steps at 59.7 and 59.4 Hz respectively).
ΔP_L = 10.0 p.u., MDR = 1.620,
$\Delta P_{\ell s}$ = 9.84 p.u.

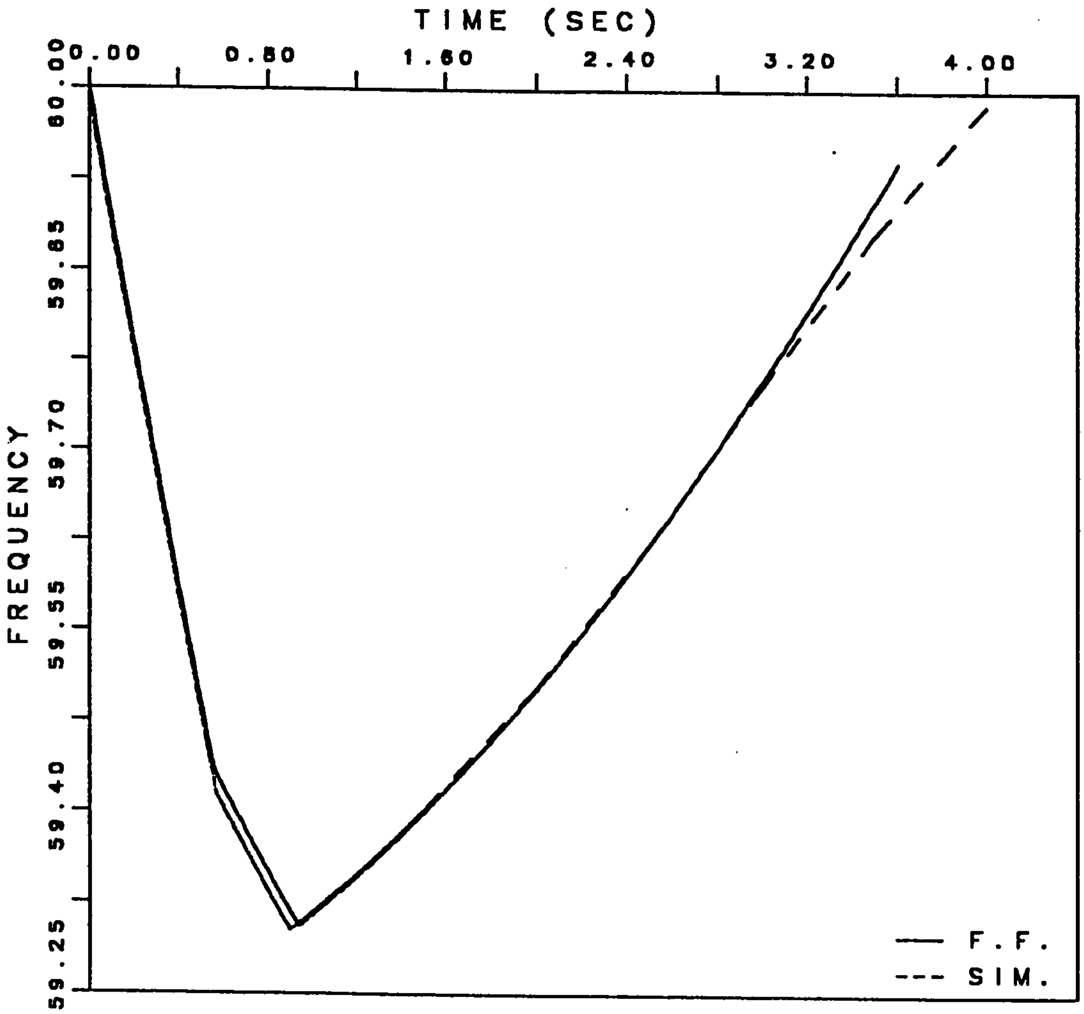

Fig. 5.7: Average system frequency transient after two stage load shedding with time delay. ΔP_L = 10.0 p.u., MDR = 1.620, $\Delta P_{\ell s}$ = 9.84 p.u.

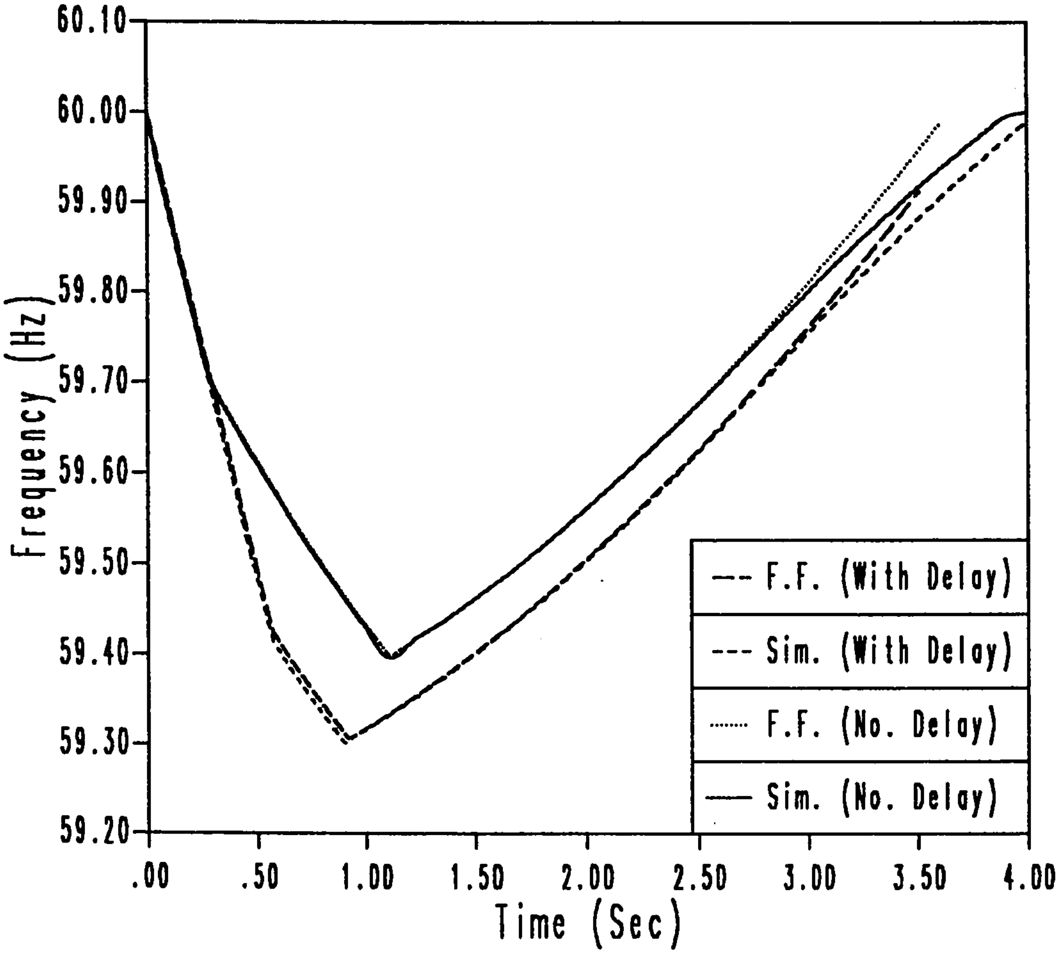

Fig. 5.8: Average system frequency transient after two stage load shedding with delay and no delay scheme (delay time is 0.28 second). ΔP_L = 10.0 p.u., MDR = 1.620, $\Delta P_{\ell s}$ = 9.84 p.u.

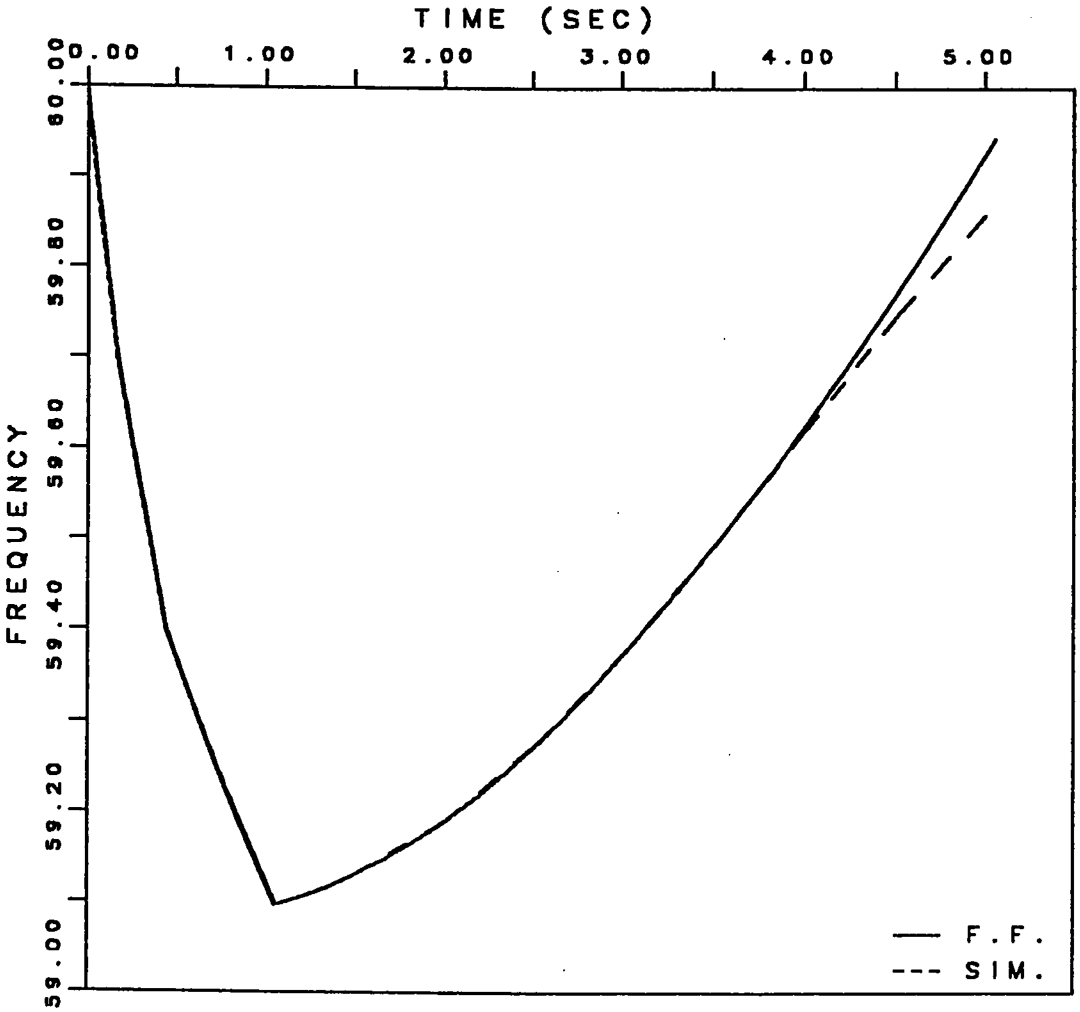

Fig. 5.9: Average system frequency transient after three step load shedding with no delay. ΔP_L = 20.4 p.u., MDR = 1.033, $\Delta P_{\ell s}$ = 14.20 p.u.

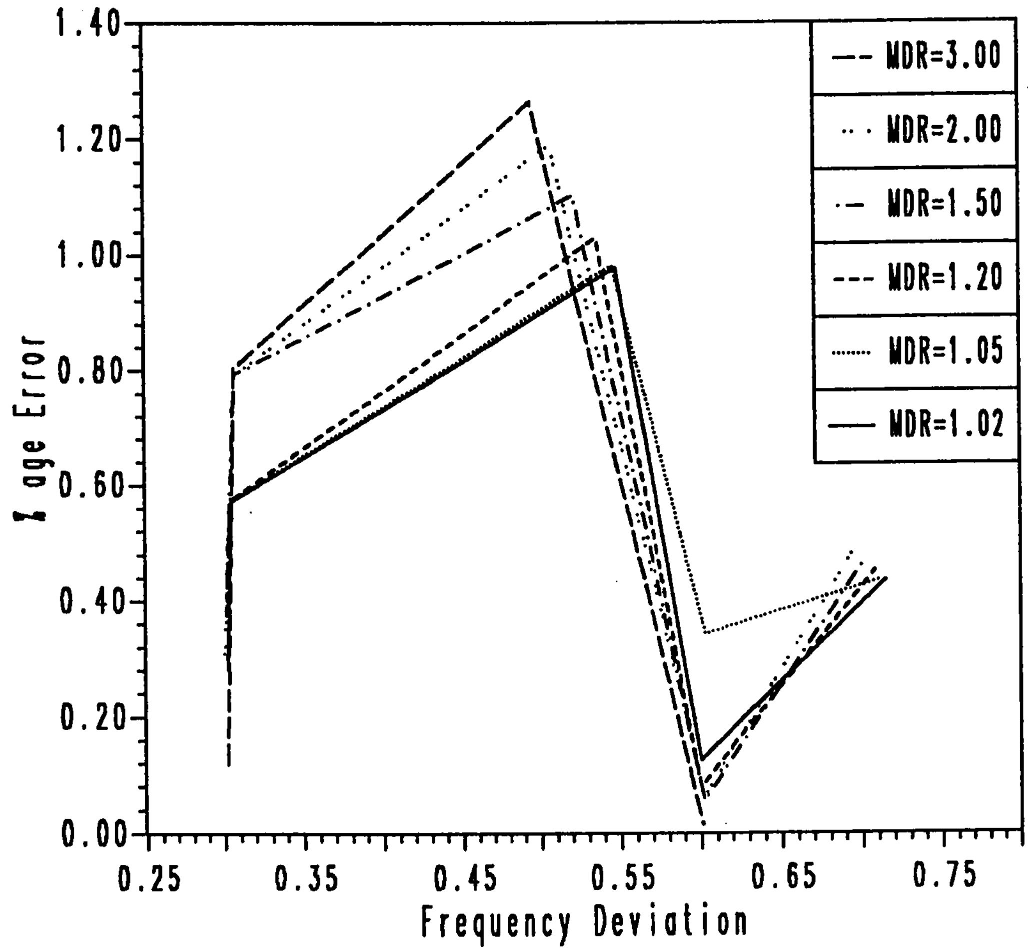

Fig. 5.10: Percentage error for different disturbances and margin to deficiency ratios with load shedding.

shed is same as for Fig. 5.6.

The comparison of frequencies using load shed scheme with and without delay is shown in Fig. 5.8. Load is shed at two set points (59.7 Hz and 59.4 Hz). For outages of generators 8 & 10, the comparison of frequencies is shown in Fig. 5.9. A total load of 23% (14.146 p.u.) is shed at three set points i.e. at 59.7, 59.4 & 59.1 Hz in steps of 9% , 7%, and 7% respectively.

The percentage error between two minimum frequencies is plotted against frequency deviation for different disturbance sizes. The behaviour of percentage error is shown in Fig. 5.10. The maximum percentage error between two frequencies is less than 1.3 for margin-to-deficiency ratio 3.0 and 10 % disturbance. The percentage error is small for frequency deviations of 0.3 and 0.6 because frequency begins to recover just after load shed. The increase in the percentage error is because the valve remains open after load shed in frequency prediction but it begins to close just after load shed.

5.3.2 Execution Time

The execution time for some time span for both the frequency prediction formula and simulation is shown in Table 5.7. The ratio of CPU time (simulation/prediction) for the occurance of minimum frequency without load shedding is shown in Fig. 5.11 (time step used to calculate frequency for simulation was 0.29 sec.). To find minimum frequency from frequency prediction formula, Newton-Raphson method was used which takes only 0.007 second. Whereas, CPU time increases with increase in disturbance size for simulation. It implies that frequency prediction formula saves 2 to 27 times CPU time when prediction is compared with simulation.

Fig. 5.12 shows the comparison of execution time for the occurance of minimum frequency after load shedding.

Time Span	CPU Time N.L.S.		CPU Time L.S.	
	F.F.	Sim.	F.F.	Sim.
1.0	0.007	0.010	0.008	0.017
2.5	0.008	0.040	0.010	0.043
5.0	0.013	0.077	0.017	0.080
7.5	0.033	0.143	0.040	0.156
10.0	0.040	0.183	0.043	0.193
12.5	0.050	0.227	0.067	0.233
15.0	0.070	0.270	0.090	0.274
20.0	0.090	0.343	0.103	0.380

Table 5.7: Comparison of CPU Time with and without load shedding.

N.L.S. = No Load Shedding
L.S. = Load Shedding Case

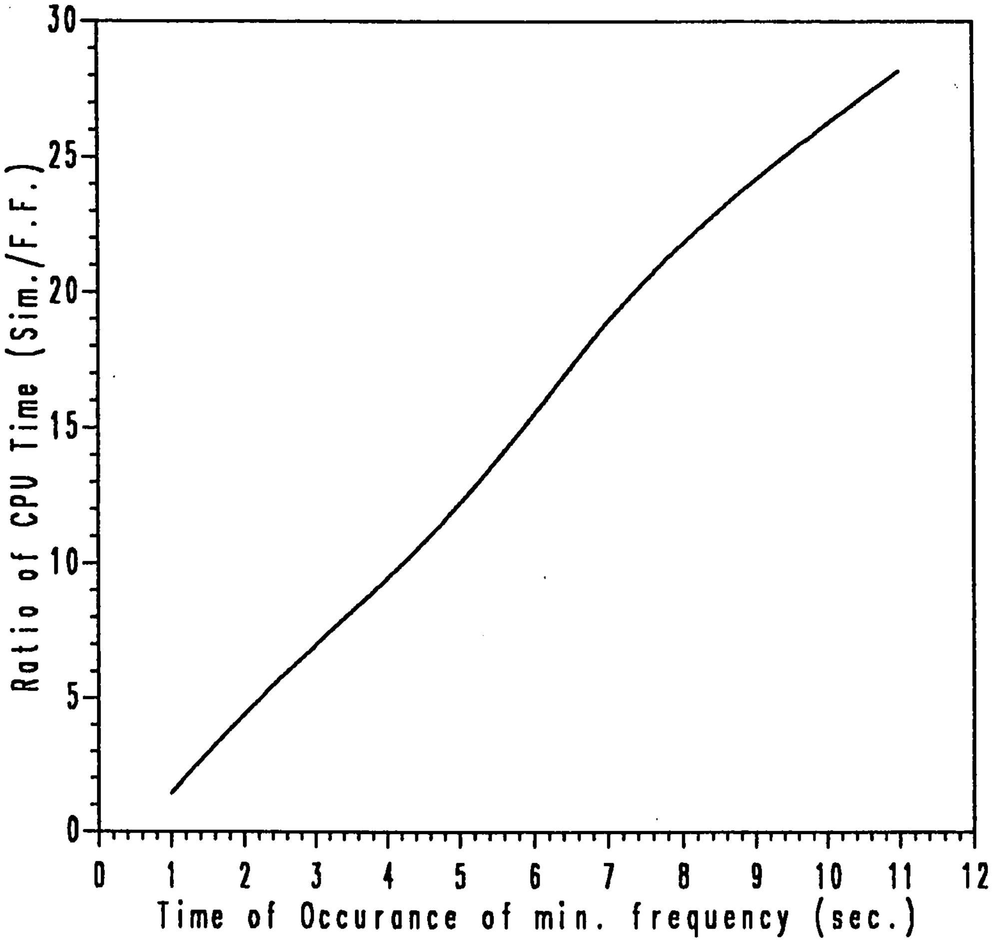

Fig. 5.11: Comparison of CPU time for the occurance minimum frequency (no load shed).

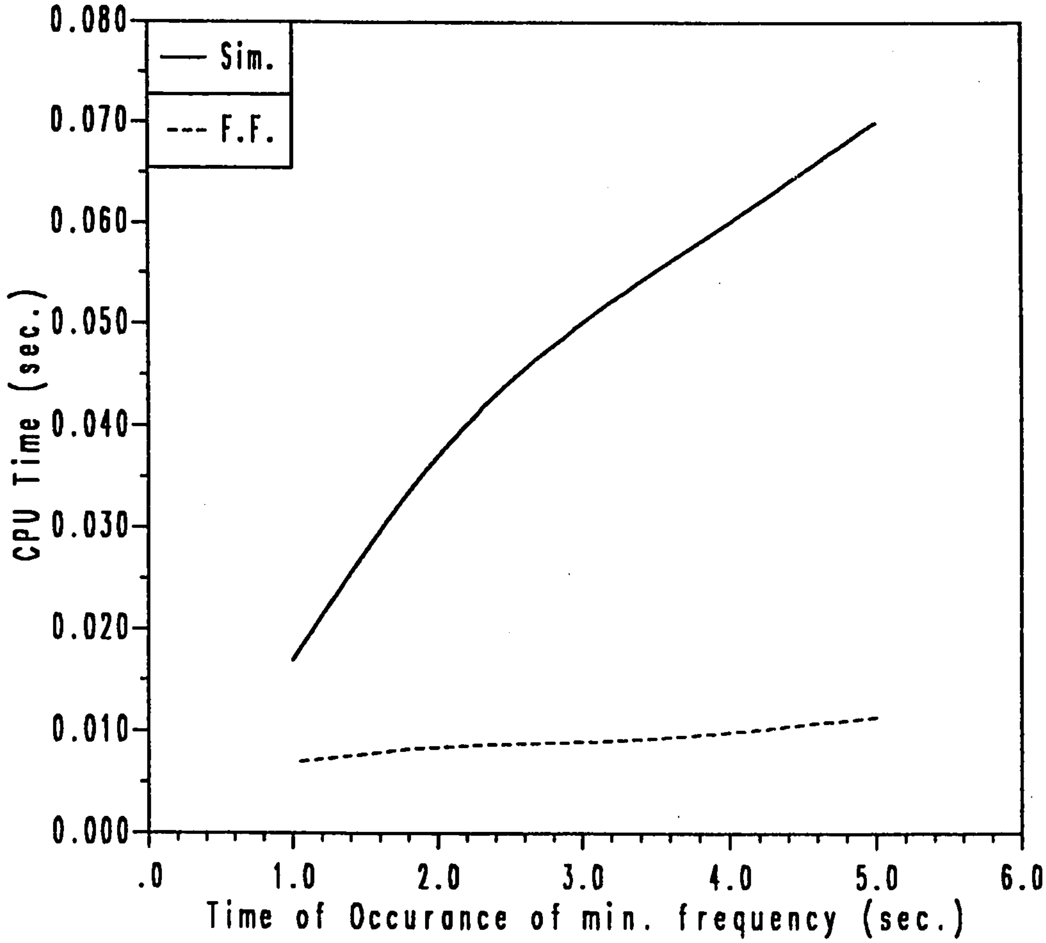

Fig. 5.12: Comparison of CPU time for the occurance of minimum frequency after load shedding.

5.4 COMPARISON OF REAL POWER $P_{ek}(t)$

The generator real power as a function of time is calculated using equation (4.3) for both frequency prediction formula and simulation. The comparison of real powers of generators 9 & 10 for contingency due to the outage of generator 4 are shown in Fig. 5.13 and Fig. 5.14 respectively. The percentage error between the powers calculated from frequency prediction formula and simulation is negligiblly small.

At 0.5 second, outage of generator # 4 has occurred (ΔP_L = 6.32 p.u.), the lost generation is picked up by the remaining generators, initial distribution of lost generation is according to their inertia. With the passage of time, the lost generation is picked up through governor response.

Fig. 5.15 shows real power of generator 7 as a function of time for the outage of generator # 4 (ΔP_L = 6.32 p.u.) with 5.54 p.u. load shed.

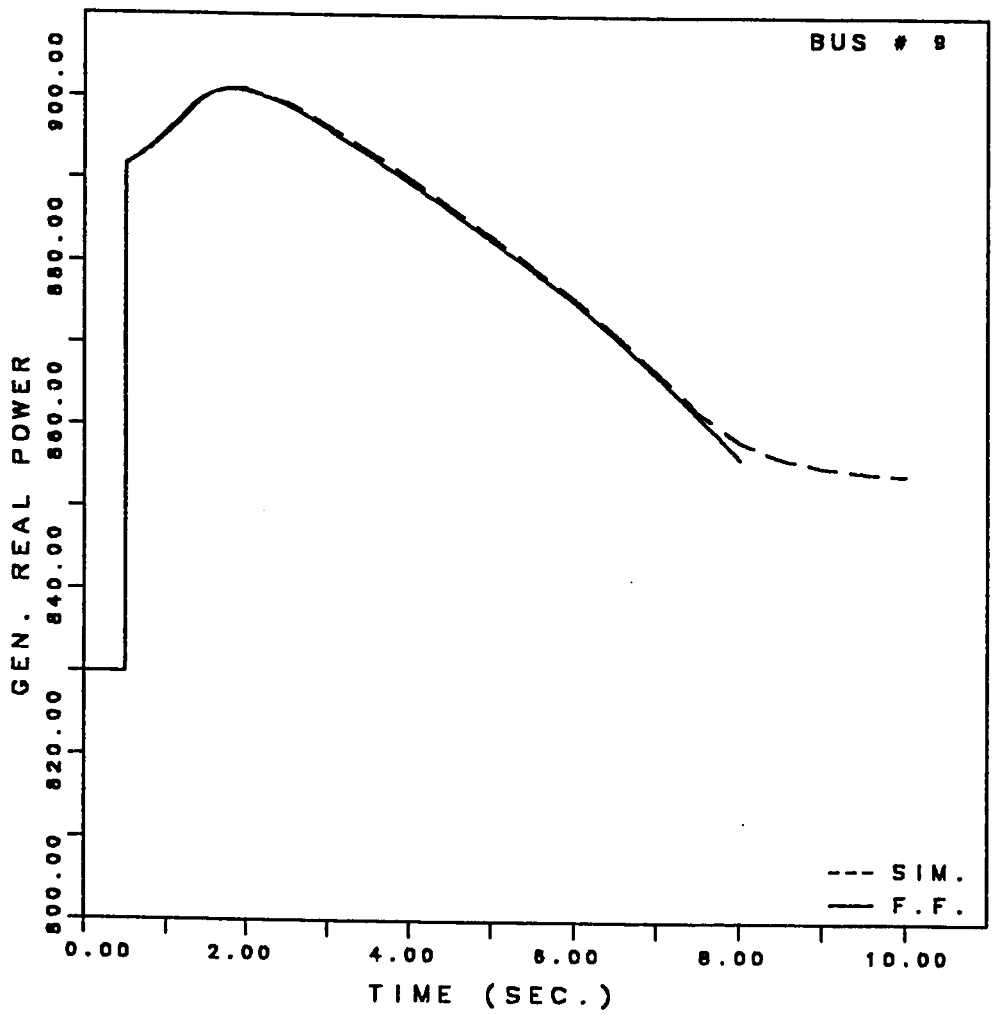

Fig. 5.13: The behaviour of real power of Gen. #9 with change in frequency due to ΔP_L = 6.32 p.u.

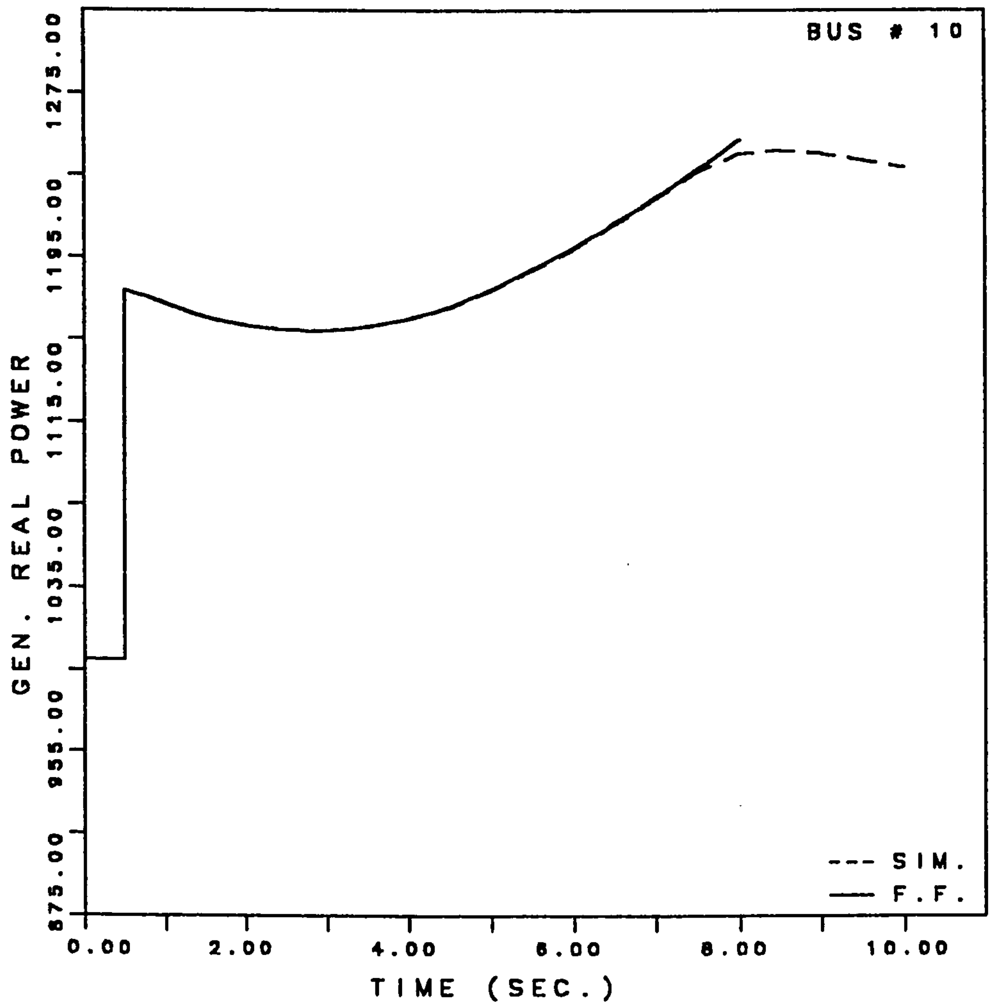

Fig. 5.14: The behaviour of real power generated at bus #10 for $\Delta P_L = 6.32$ p.u.

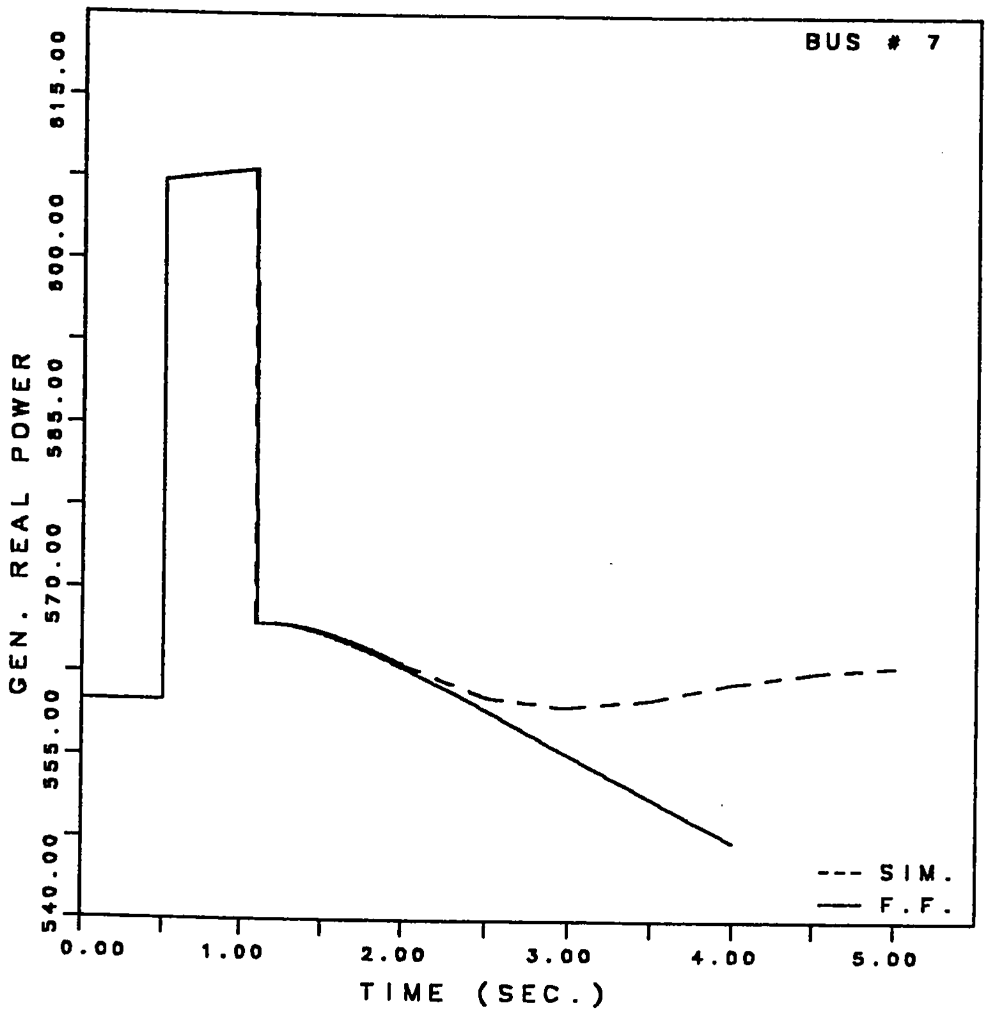

Fig. 5.15: Real power generated at bus # 7 after load shedding with no delay. $\Delta P_L = 6.32$ p.u.

5.5 RESULTS FROM DYNAMIC LOAD FLOW

The generator real power as a function of time is used to calculate reactive power $Q_{ek}(t)$, bus voltage $v(t)$, bus angles $\theta(t)$ and line flows $P_{jk}(t)$ from Fast Decoupled Load flow program.

5.5.1 Reactive Power $Q_{ek}(t)$

The plot of reactive power of generator #3 as a function of time for the outage of generator #6 is shown in Fig. 5.16. Real power loss was 6.5 p.u. and reactive power loss was 2.75 p.u.

Figure 5.17 shows the reactive power of generator #3 as a function of time for 9 % of real and reactive load shed. The percentage error between two reactive powers (from frequency prediction and simulation) is small.

5.5.2 Bus Voltage $v(t)$

Most power plant auxiliaries driven by induction motor loads have undervoltage relays that trip the motors when the voltage is too low for safe operation. Generating units may experience steady state instability when the bus voltage is too low.

The behaviour of voltage at bus #15 for the outage of generator #6 is shown in Fig. 5.18. Real power lost was 6.5

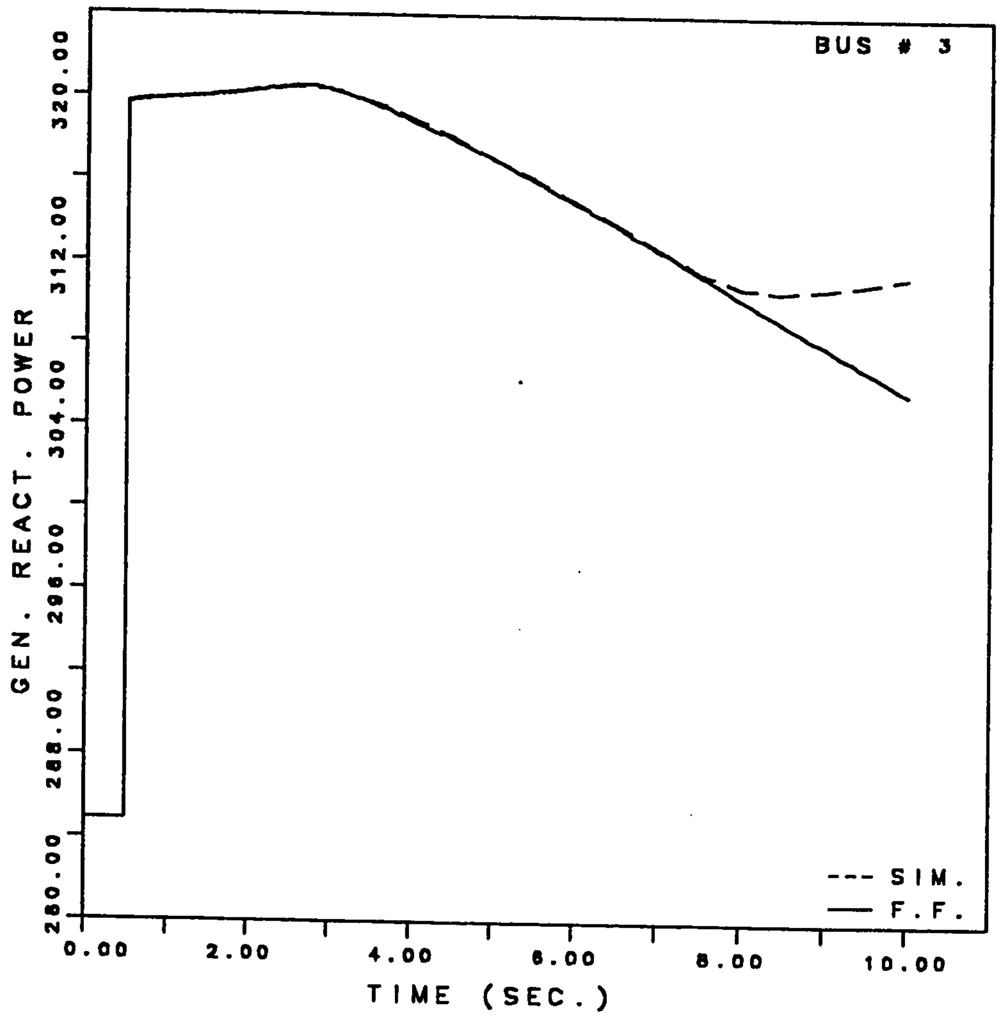

Fig. 5.16: Reactive power generated at bus #3 for a loss of 2.75 p.u.(275 MVAr). ΔP_L = 6.50 p.u., ΔQ_L = 2.75 p.u.

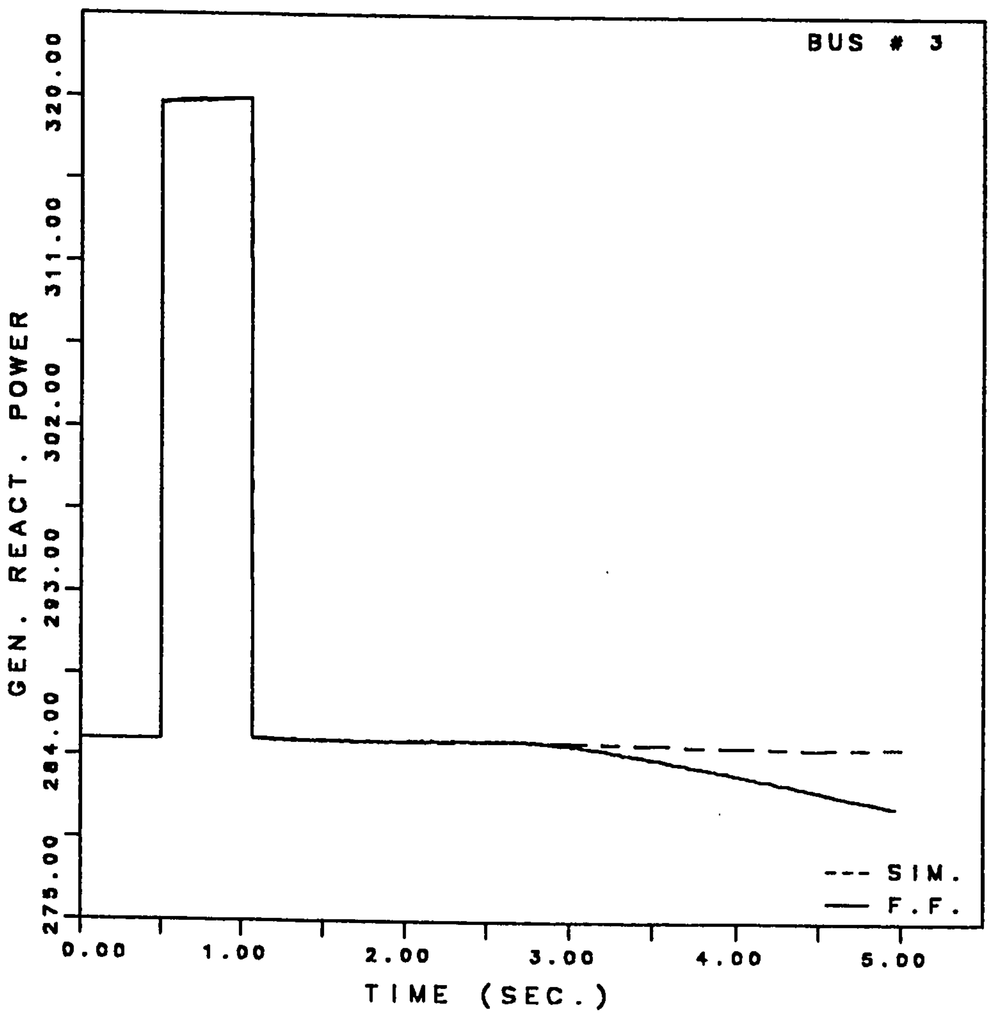

Fig. 5.17: Reactive power generated at bus #3 after 9.0% reactive load shed. $\Delta P_L = 6.50$ p.u., $\Delta Q_L = 2.75$ p.u.

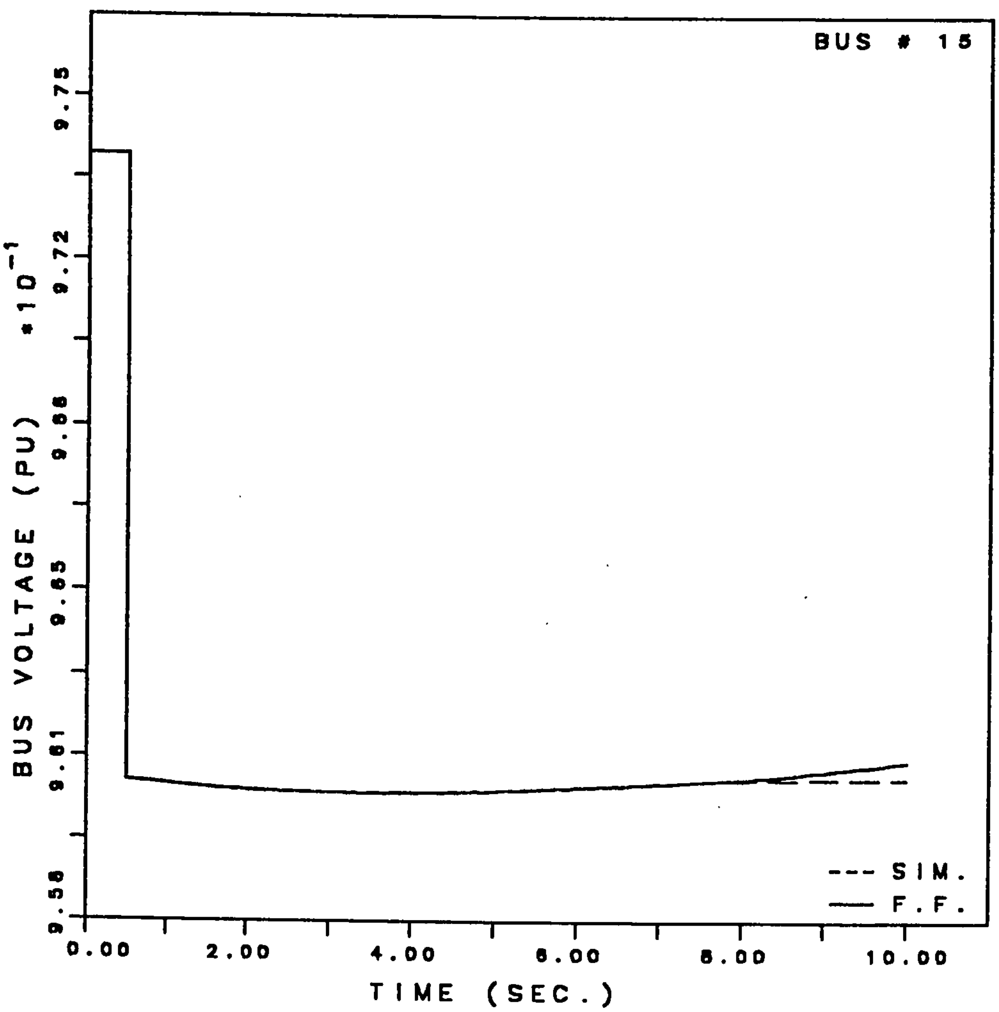

Fig. 5.18: Voltage at bus # 15 for
ΔP_L = 6.50 p.u., ΔQ_L = 2.75 p.u.

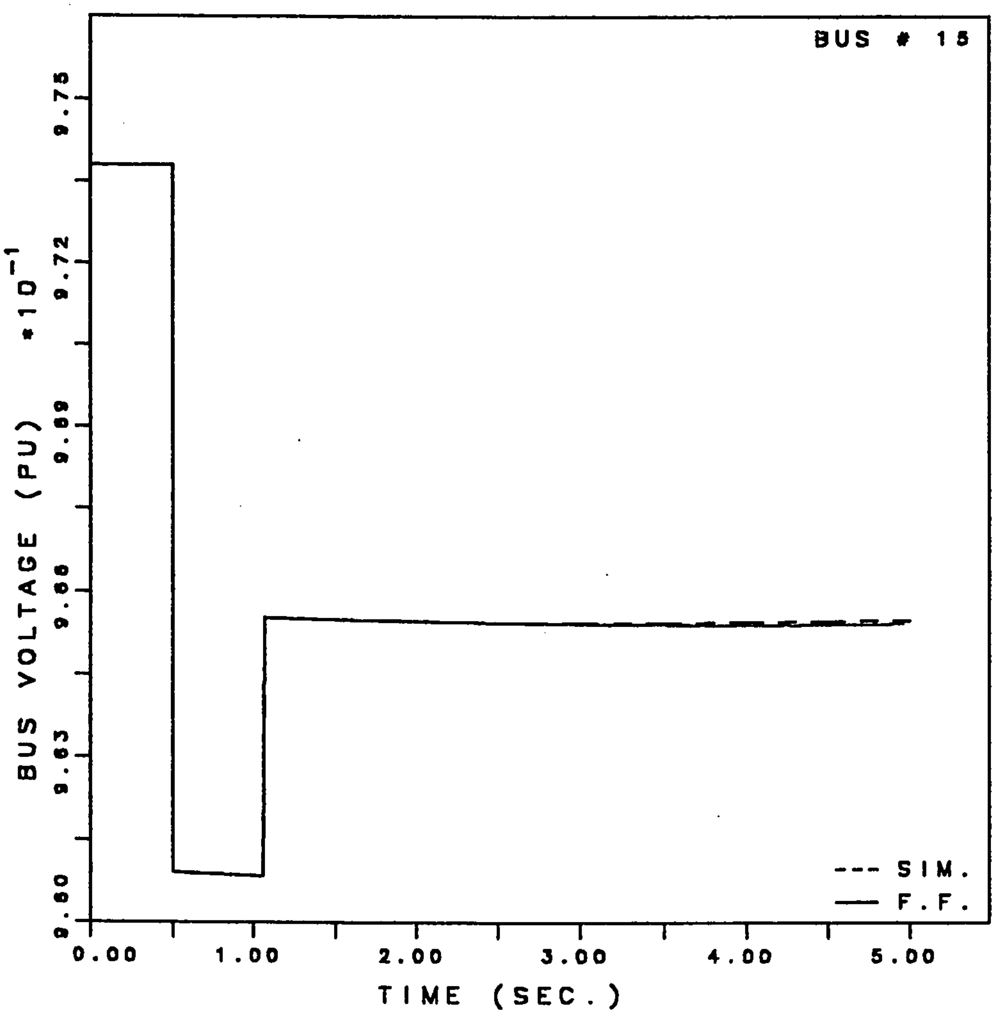

Fig. 5.19: Voltage at bus # 15 after 9.0% of real and reactive load shed.
ΔP_L = 6.50 p.u., ΔQ_L = 2.75 p.u.

p.u. and reactive power lost was 2.75 p.u.

The voltage at bus #15 as a function of time for 5.45 p.u. of real load and 1.27 of reactive load shed is shown in Fig. 5.19.

5.5.3 Bus Phase Angle $\theta(t)$

The change in bus phase angles $\Delta\theta$ for a given set of changes in bus power injections ΔP is given by

$$\Delta\theta = [X]\,\Delta P$$

So, bus phase angle θ is dependent on bus power injections. The behaviour of phase angle of bus #10 for the outage of generator #6 is shown in Fig. 5.20. The percentage error between two angles is small. Figure 5.21 shows the phase angle of bus # 5 as a function of time for 5.54 p.u. of real and 1.27 of reactive load shed.

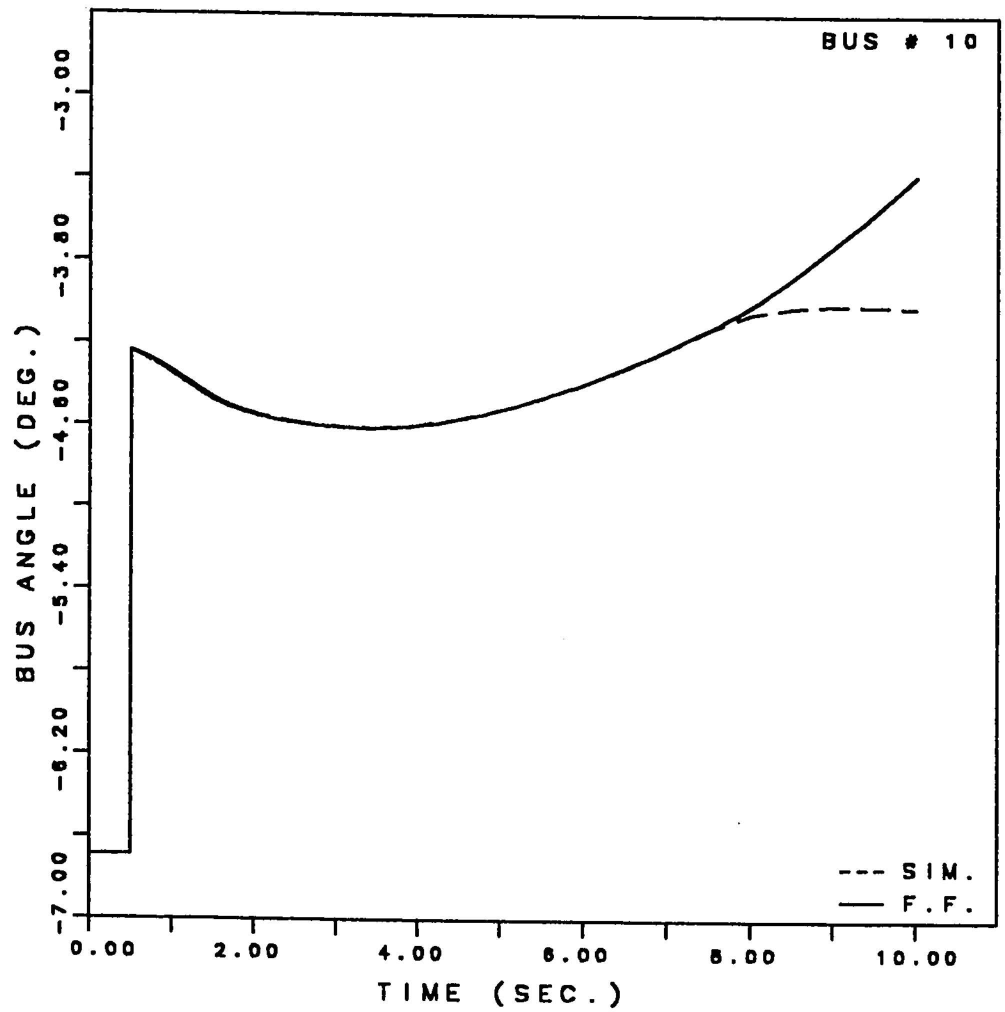

Fig. 5.20: Phase angle of bus # 10 for the outage of Generator #6 .
ΔP_L = 6.50 p.u., ΔQ_L = 2.75 p.u.

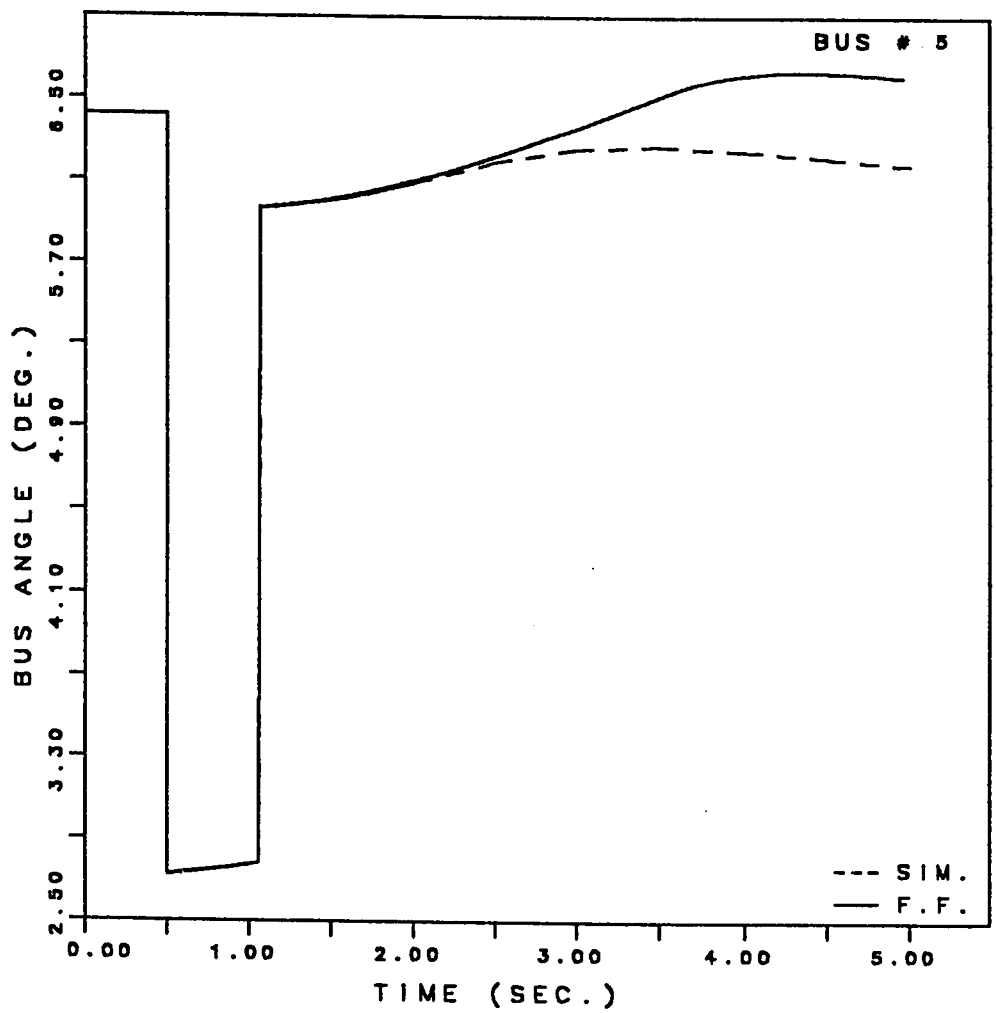

Fig. 5.21: Phase angle of bus # 10 after 9.0% of real and reactive load shed for the outage of Generator #6.
ΔP_L = 6.50 p.u., ΔQ_L = 2.75 p.u.

5.5.4 Line Flows $P_{jk}(t)$

The flow of real and reactive powers from Bus #14 to Bus #15 for the outage of generator # 6 are shown in figures 5.22 and 5.23 respectively.

The figures 5.24 and 5.25 shows the flow of real and reactive powers from Bus #14 to Bus #15 after 9 % of real and reactive load shed. The disturbance given to the test system was outage of generator #6.

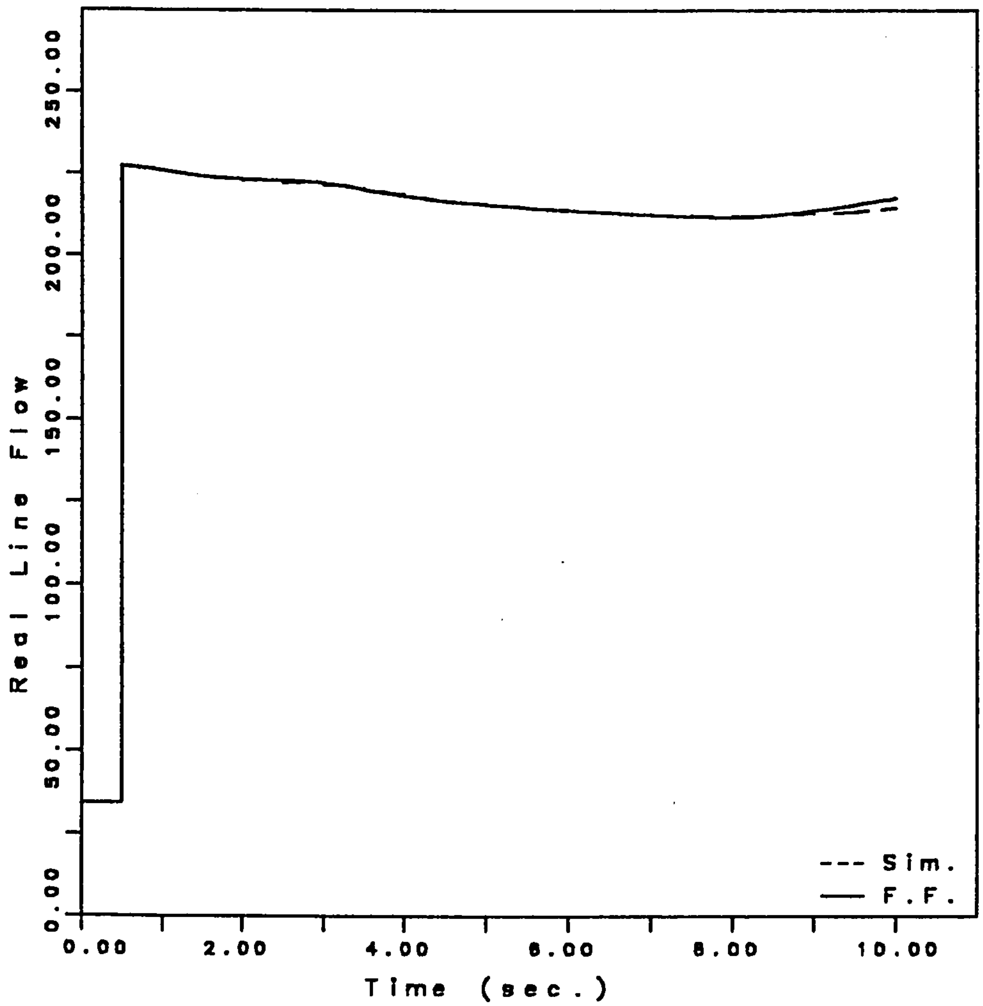

Fig. 5.22: The flow of real power from Bus #14 to Bus #15 for the outage of Gen. #6. $\Delta P_L = 6.50$ p.u., $\Delta Q_L = 2.75$ p.u.

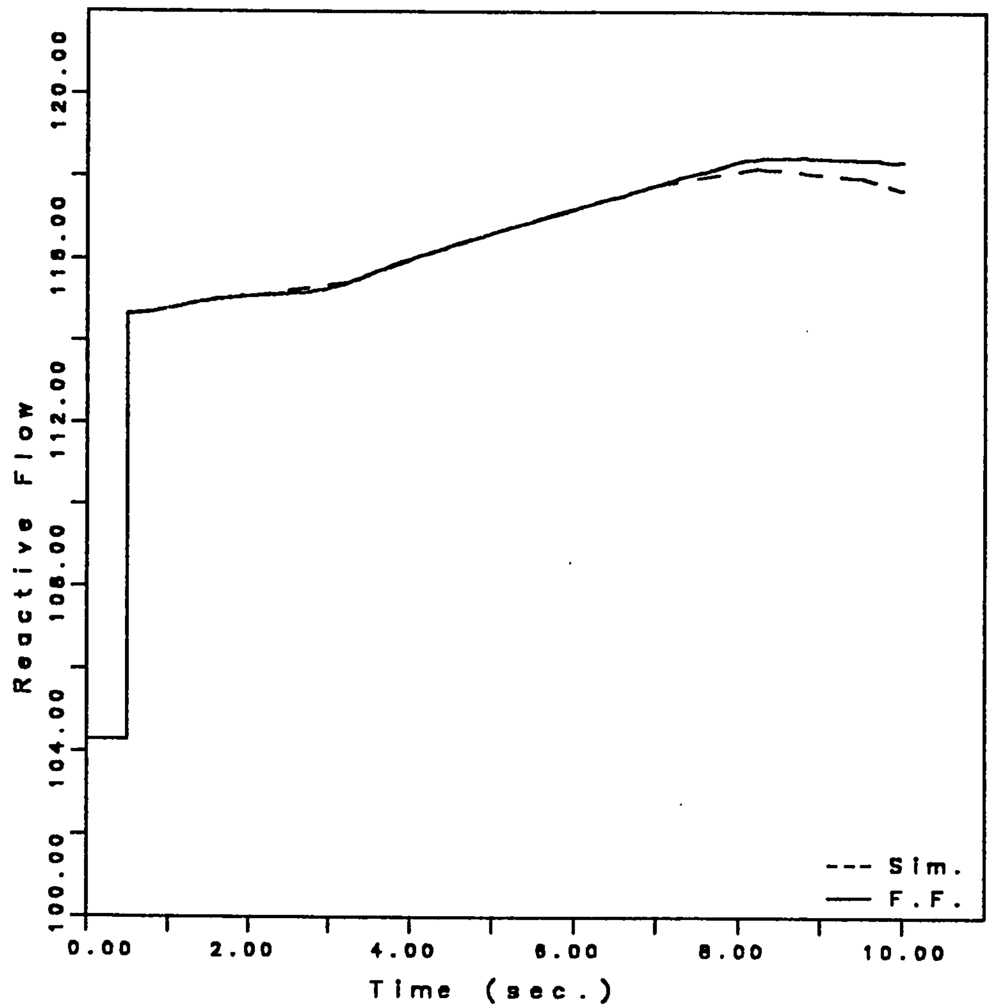

Fig. 5.23: The flow of reactive power from Bus #14 to Bus #15 for the outage of Gen. #6. ΔP_L = 6.50 p.u., ΔQ_L = 2.75 p.u.

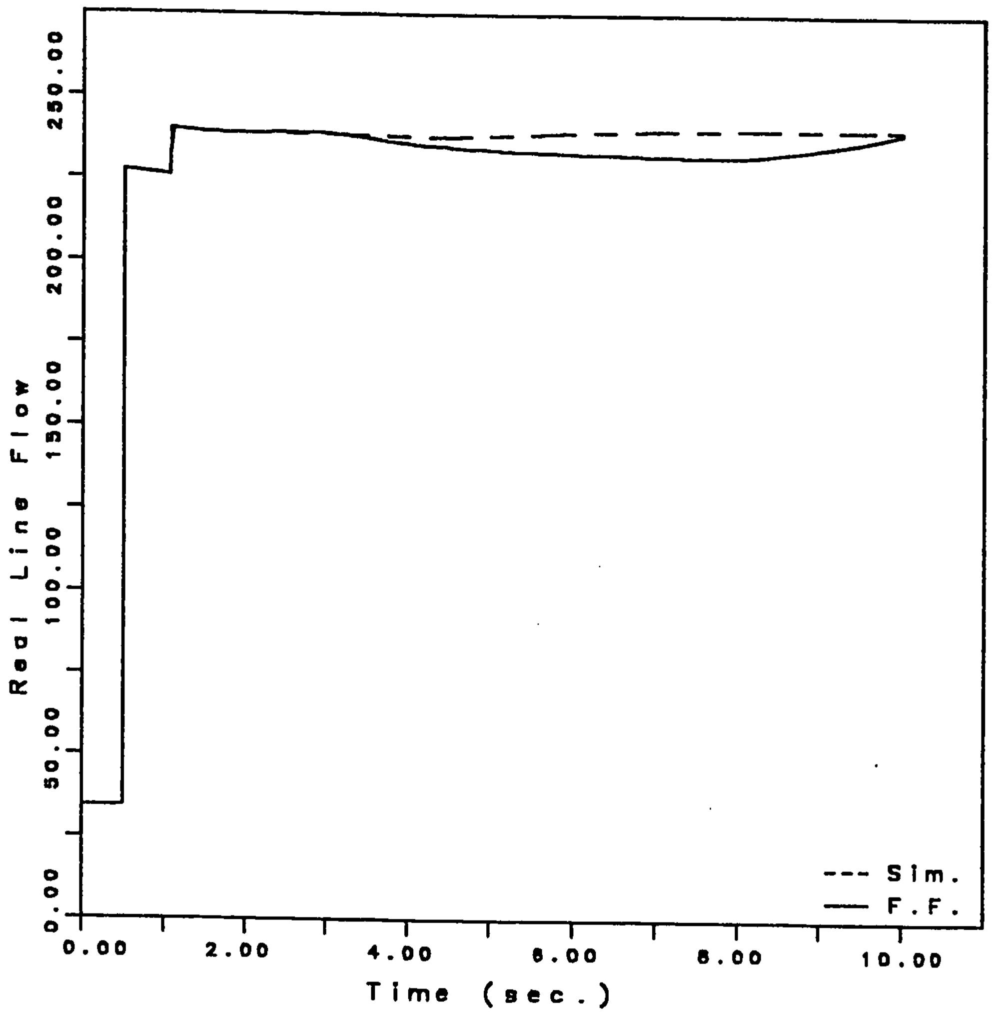

Fig. 5.24: The flow of real power from Bus #14 to Bus #15 after 9 % of load shed for the outage of Generator #6.
$\Delta P_L = 6.50$ p.u., $\Delta Q_L = 2.75$ p.u.
$\Delta P_{\ell s} = 5.54$ p.u.

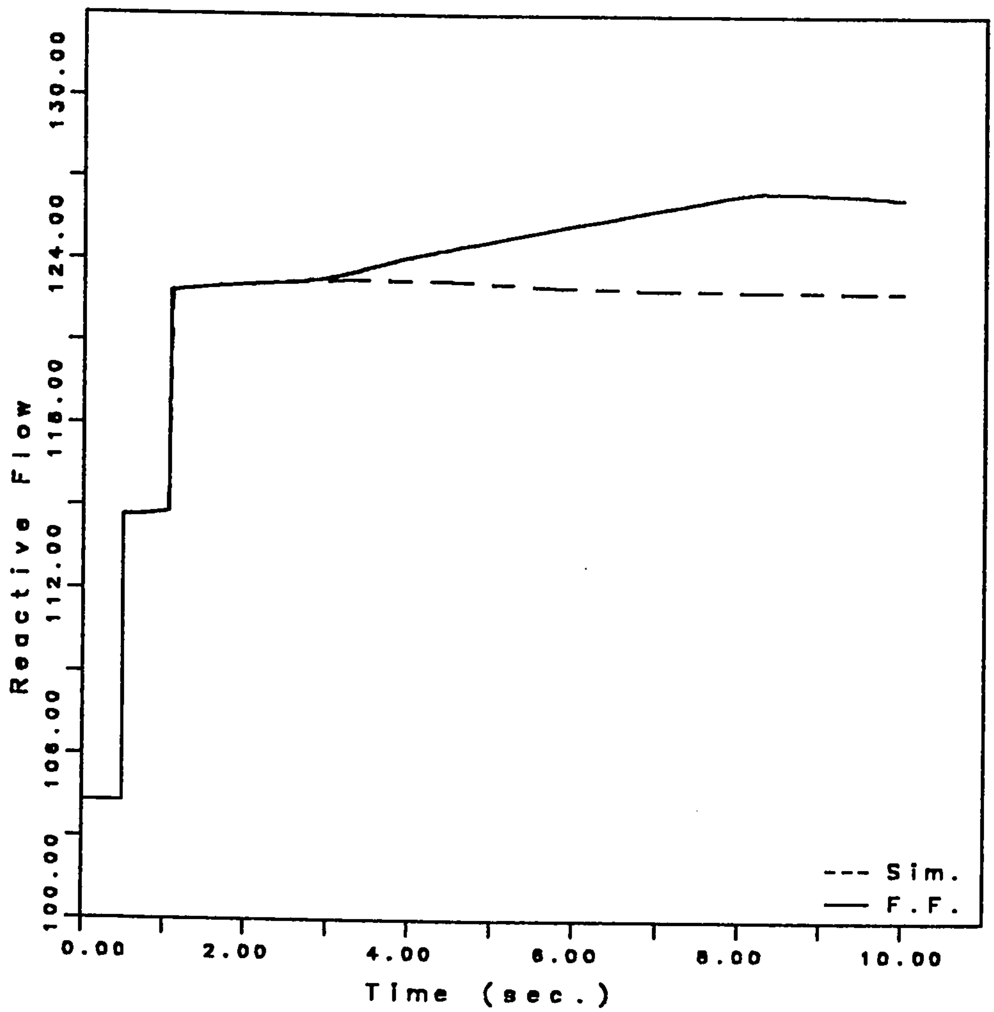

Fig. 5.25: The flow of reactive power from Bus #14 to Bus #15 after 9 % of load shed for the outage of Generator #6.
ΔP_L = 6.50 p.u., ΔQ_L = 2.75 p.u.
$\Delta P_{\ell s}$ = 5.54 p.u.

5.6 RANKING OF CONTINGENCIES

One iteration of Fast Decoupled Power Flow is used to calculate the real power performance index for each outage case. Outages are then ranked according to their corresponding performance indices.

Case I: Ranking based on Maximum Frequency Deviation

Table 5.8 shows the ranking of contingencies base on real power performance index. The ranking of generator outage contingencies based on maximum frequency deviation is shown in the same table. The comparison of the ranking based on real power and maximum frequency deviation is also shown.

The ranking of generator outage contingencies based on frequency and line flow performance indices is almost same except one outage case. Outage of generator 4 is less severe in line flow based performance index whereas according to frequency transient based performance index, the outage of generator 4 is very severe. However, for the outage of generator 7 the ranking is opposite i.e. the outage of generator 7 is less severe from frequency point of view and very severe according to line flow based performance index.

Outage Case	MDR	ΔP_L pu	f_{min} Hz	PI_f	PI_{MW}	Ranking PI_f	Ranking PI_{MW}
1	6.94	2.7	59.688	0.139	3.405	10	10
2	4.51	5.6	59.047	1.530	31.316	6	6
3	3.91	6.5	58.780	2.727	34.064	5	5
4	3.56	6.3	58.803	2.960	30.091	3	7
5	4.97	5.1	59.201	1.013	22.962	9	8
6	3.79	6.5	58.740	2.932	36.895	4	4
7	4.64	5.6	59.094	1.387	38.397	7	3
8	4.80	5.4	59.150	1.208	9.125	8	9
9	3.11	8.3	58.175	7.184	66.374	2	2
10	1.61	10.0	56.765	52.564	121.558	1	1

Table 5.8: Ranking of outage contingencies based on frequency and real power indices.

The ranking of multiple outage contingencies based on real power and frequency deviation performance indices is shown in Table 5.9. The comparison of ranking is also shown in the same table.

Case II: Ranking based on Load Shedding

The ranking of single and multiple contingencies based on frequency performance indicies is shown in Table 5.10. The comparison in also shown. The ranking of sixty percent contingencies based on maximum frequency deviation and load shedding is exactly the same. The remaining forty percent contingencies are almost the same in ranking. The differences are due to the maximum frequency deviation after load shedding, because, sometimes frequency starts recovering just after load shed. For these cases, excess amount of load was shed.

Outage Case	MDR	ΔP_L pu	f_{min} Hz	PI_f	PI_{MW}	Ranking PI_f	Ranking PI_{MW}
1	6.94	2.7	59.688	0.139	3.405	49	49
2	4.51	5.6	59.047	1.530	31.316	45	44
3	3.91	6.5	58.780	2.727	34.064	44	42
4	3.56	6.3	58.803	2.960	30.091	42	46
5	4.97	5.1	59.201	1.013	22.962	48	47
6	3.79	6.5	58.740	2.932	36.895	43	39
7	4.64	5.6	59.094	1.387	38.397	46	36
8	4.80	5.4	59.150	1.208	9.125	47	48
9	3.11	8.3	58.175	7.184	66.374	41	27
10	1.61	10.0	56.765	52.564	121.558	16	5
1, 2	2.13	8.29	57.798	16.158	35.984	37	41
1, 3	1.93	9.15	57.395	25.663	37.174	32	38
1, 4	1.64	8.97	57.334	37.301	39.492	27	35
1, 5	2.26	7.73	58.070	11.835	31.157	40	45
1, 6	1.85	9.15	57.299	29.179	42.244	29	32
1, 7	2.21	8.25	57.920	14.233	36.492	38	40
1, 8	2.26	8.05	57.990	12.866	33.149	39	43
1, 9	1.65	10.95	56.515	58.848	85.592	14	19
2, 3	2.03	12.13	56.179	44.982	101.540	21	12
2, 4	1.82	11.95	56.089	57.281	66.846	15	26
2, 5	2.28	10.71	56.966	25.320	64.519	33	28
2, 6	1.97	12.13	56.069	49.235	69.308	18	24
2, 7	2.24	11.23	56.786	29.061	69.708	30	23
2, 8	2.28	11.03	56.860	27.081	39.973	31	34
2, 9	1.80	13.93	55.213	83.691	93.119	8	16
3, 4	1.70	12.80	55.604	81.143	70.003	9	22
3, 5	2.11	11.58	56.549	35.867	68.179	28	25
3, 6	1.84	13.00	55.593	68.305	72.802	12	21
3, 7	2.08	12.10	56.355	40.727	73.429	24	20
3, 8	2.12	11.90	56.429	38.121	40.261	26	33
3, 9	1.69	14.80	54.699	113.218	94.323	6	15

Table 5.9: Ranking of multiple outage contingencies based on frequency and real power indices.

Table 5.9 continued

Outage Case	MDR	ΔP_L pu	f_{min} Hz	PI_f	PI_{MW}	Ranking PI_f	Ranking PI_{MW}
4, 5	1.89	11.40	56.470	45.142	98.664	20	13
4, 6	1.64	12.82	55.469	91.325	119.846	7	6
4, 7	1.87	11.92	56.280	51.054	102.771	17	11
4, 8	1.90	11.72	56.355	47.622	43.831	19	30
4, 9	1.51	14.62	54.547	155.318	121.978	4	4
5, 6	2.05	11.58	56.447	39.201	97.232	25	14
5, 7	2.34	10.68	57.109	22.976	89.919	35	17
5, 8	2.39	10.48	57.179	21.351	37.647	36	37
5, 9	1.86	13.38	55.653	67.650	108.768	13	9
5,10	1.01	15.08	53.307	9881.370	124.793	1	3
6, 7	2.02	12.10	56.251	44.432	103.221	22	10
6, 8	2.05	11,90	56.326	41.578	42.505	23	31
6, 9	1.64	14.80	54.563	125.314	119.839	5	7
7, 8	2.34	11.00	57.008	24.608	45.213	34	29
7, 9	1.84	13.90	55.426	75.501	114.545	10	8
7,10	1.02	15.60	52.595	4840.040	126.668	2	2
8, 9	1.87	13.70	55.504	71.136	88.616	11	18
8,10	1.03	15.40	53.027	3217.118	140.060	3	1

Outage Case	MDR	ΔP_L pu	$\Delta P_{\ell s}$ pu	PI_f	$PI_{\ell s}$	Ranking PI_f	Ranking $PI_{\ell s}$
1	6.94	2.65	5.54	0.139	0.28	49	49
2	4.51	5.63	5.54	1.530	0.47	45	45
3	3.91	6.50	5.54	2.727	0.58	44	44
4	3.56	6.32	5.54	2.960	0.66	42	42
5	4.97	5.08	5.54	1.013	0.42	48	48
6	3.79	6.50	5.54	2.932	0.61	43	43
7	4.64	5.60	5.54	1.387	0.46	46	46
8	4.80	5.40	5.54	1.208	0.44	47	47
9	3.11	8.30	5.54	7.184	1.24	41	41
10	1.61	10.00	9.84	52.564	9.59	16	12
1, 2	2.13	8.29	5.54	16.158	2.53	37	37
1, 3	1.93	9.15	9.84	25.663	6.33	32	23
1, 4	1.64	8.97	9.84	37.301	9.18	27	14
1, 5	2.26	7.73	5.54	11.835	1.84	40	40
1, 6	1.85	9.15	9.84	29.179	6.95	29	19
1, 7	2.21	8.25	5.54	14.233	2.29	38	38
1, 8	2.26	8.05	9.84	12.866	2.05	39	39
1, 9	1.65	10.95	9.84	58.848	9.10	14	16
2, 3	2.03	12.13	9.84	44.982	6.20	21	25
2, 4	1.82	11.95	9.84	57.281	7.64	15	17
2, 5	2.28	10.71	9.84	25.320	4.07	33	36
2, 6	1.97	12.13	9.84	49.235	6.61	18	22
2, 7	2.24	11.23	9.84	29.061	4.77	30	31
2, 8	2.28	11.03	9.84	27.081	4.64	31	32
2, 9	1.80	13.93	14.15	83.691	15.94	8	7
3, 4	1.70	12.80	9.84	81.143	10.58	9	10
3, 5	2.11	11.58	9.84	35.867	5.35	28	30
3, 6	1.84	13.00	9.84	68.305	9.16	12	15
3, 7	2.08	12.10	9.84	40.727	5.81	24	27
3, 8	2.12	11.90	9.84	38.121	5.52	26	29
3, 9	1.69	14.80	14.15	113.218	18.37	6	6

Table 5.10: Ranking of outage contingencies based on frequency performance indices.

Table 5.10 continued

Outage Case	MDR	ΔP_L pu	$\Delta P_{\ell s}$ Hz	PI_f	$PI_{\ell s}$	Ranking PI_f	Ranking $PI_{\ell s}$
4, 5	1.89	11.40	9.84	45.142	6.68	20	21
4, 6	1.64	12.82	9.84	91.325	11.63	7	9
4, 7	1.87	11.92	9.84	51.054	7.12	17	18
4, 8	1.90	11.72	9.84	47.622	6.76	19	20
4, 9	1.51	14.62	14.15	155.318	24.48	4	4
5, 6	2.05	11.58	9.84	39.201	5.71	25	28
5, 7	2.34	10.68	9.84	22.976	4.39	35	34
5, 8	2.39	10.48	9.84	21.351	4.26	36	35
5, 9	1.86	13.38	9.84	67.650	9.45	13	13
5,10	1.01	15.08	14.15	9881.370	1250.31	1	1
6, 7	2.02	12.10	9.84	44.432	6.22	22	24
6, 8	2.05	11,90	9.84	41.578	5.86	23	26
6, 9	1.64	14.80	14.15	125.314	19.81	5	5
7, 8	2.34	11.00	9.84	24.608	4.42	34	33
7, 9	1.84	13.90	14.15	75.501	15.07	10	8
7,10	1.02	15.60	14.15	4840.040	563.16	2	2
8, 9	1.87	13.70	9.84	71.136	10.03	11	11
8,10	1.03	15.40	14.15	3217.118	382.43	3	3

5.6.1 Execution Time

The CPU time required to calculate the performances indices is shown in Table 5.11. It is clear from the above mentioned table that CPU time required to calculate the frequency deviation performance indies from frequency prediction formula is at most $\frac{1}{5}$ of the CPU time required by simulation. Whereas, the CPU time required to calculate the real power performance index is thirty times more than the CPU time required by frequency prediction formula. One iteration of Fast Decoupled Load Flow was used to calculate the real power performance index.

	CPU Time	
	minimum	maximum
Load Flow	0.23	0.27
Frequency Prediction Formula N.L.S.	0.007	0.007
Simulation N.L.S.	0.010	0.200
Frequency Prediction Formula L.S.	0.007	0.017
Simulation L.S.	0.017	0.100

Table 5.11: Execution Time per outage case for performance indices.

N.L.S= No Load Shed

L.S = Load Shed

5.7 COMPARISON OF LINEAR AND RATE OF CHANGE OF FREQUENCY DEPENDENCE LOAD SHED SCHEMES

The rate of change of frequency dependence load shed scheme designed in this thesis is tested on IEEE 39-bus system for different load disturbances and results are compared with linear type load shed scheme given by [9]. Fig. 5.26 shows the comparison of frequency transients for a load disturbance of 2.65 p.u. It is clear from figure that there is no need to shed the load. The linear type scheme sheds 5.54 p.u. (9 %) of load, whereas, no load is shed by the rate of change of frequency dependence scheme. For the case of medium load disturbances, the behaviour of both the schemes is almost same as shown in Fig. 5.27 for a load disturbance of 10.0 p.u. For large disturbances, the rate of change of frequency dependence scheme gave good results when compared with linear type load shed scheme. The comparison of frequency transients using two schemes for large disturbances is shown in Fig.5.28 and Fig.5.29.

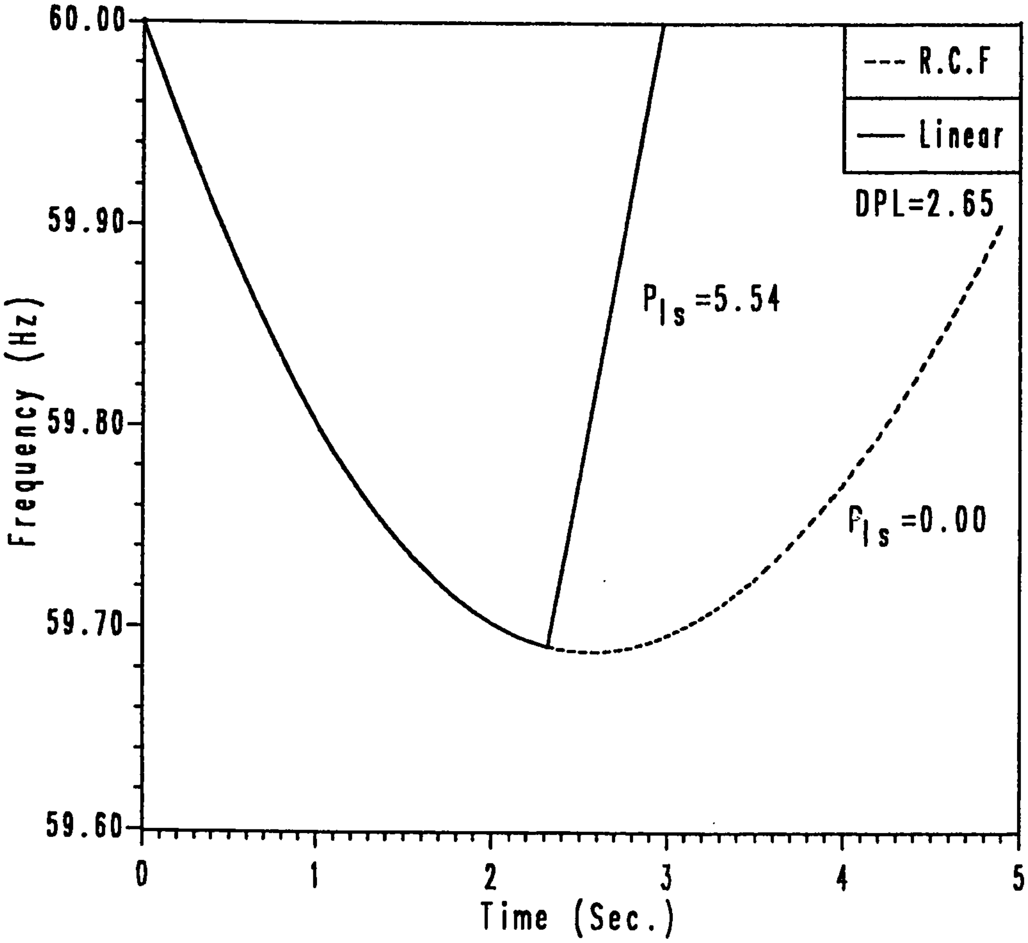

Fig. 5.26: Comparison of two load shed schemes for a load disturbance of 2.65 p.u.

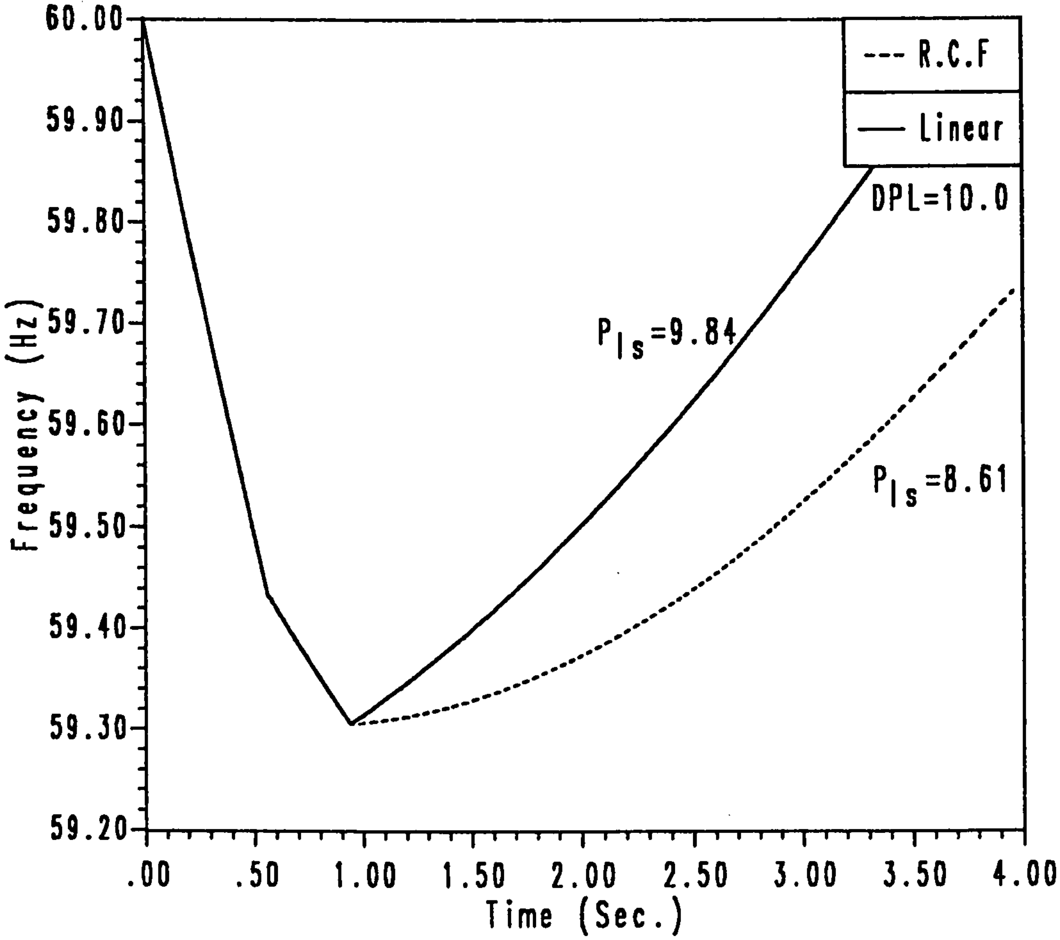

Fig. 5.27: Comparison of two load shed schemes for the outage of generator # 10. ΔP_L = 10.0 p.u.

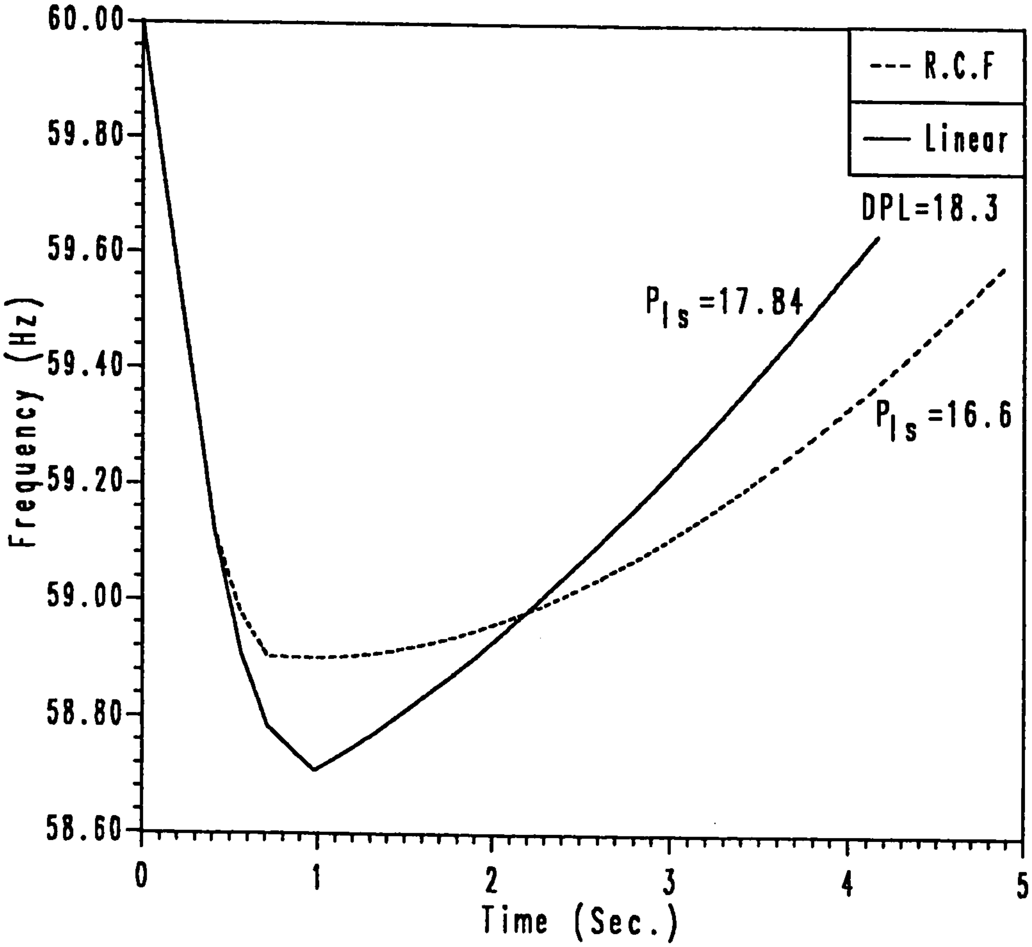

Fig. 5.28: Comparison of two load shed schemes for the outage of 9th & 10th generator. ΔP_L = 18.3 p.u.

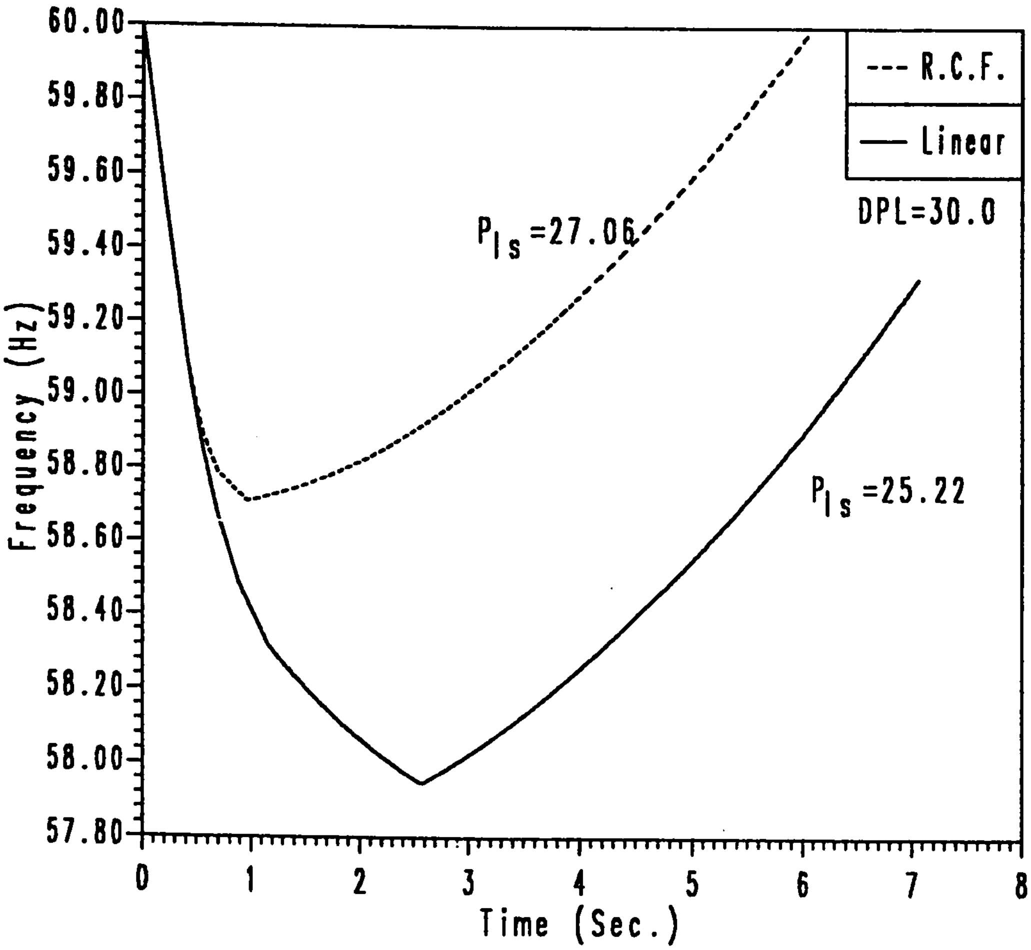

Fig. 5.29: Comparison of two load shed schemes for a load disturbance of 30.0 p.u.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 SUMMARY

In this thesis, the effects of frequency transients on dynamic performance of power system, following loss of generation or load contingencies, are studied. Following are the contributions of the thesis:

(1) A dynamic contingency analysis program has been developed for evaluating the effect of loss of generation or load contingencies on frequency transients.

(2) This program is developed incorporating the proposed general frequency prediction formula which takes care of load shedding and multiple contingencies.

(3) A dynamic load flow program is produced by combining the frequency prediction formula with the fast decoupled load flow program. It computes bus angle, bus voltage, line flows, generator real and reactive power.

(4) Two frequency performance indices are proposed to

rank critical contingencies based on load disturbance, minimum frequency, and amount of load shed, etc.

(5) A rate of change of frequency dependence load shed scheme has been developed and compared with one of the existing load shed schemes.

6.2 CONCLUSIONS

Based on the study presented in this thesis, the following conclusions have been drawn:

(1) The frequency prediction formula compares well with the average system frequency simulation. The percentage error between the frequencies is less than 3 % for disturbance size greater than 5.0. For large disturbances and MDR ranging from 1.02 to 4.0, the percentage error is less than 1.

(2) The saving in CPU time is 2 to 27 times when frequency prediction is compared with simulation for the prediction of minimum frequency.

(3) Several generation outage contingency analyses were performed. The saving in CPU time per generation outage case is at least 2 times when compared with simulation and 30 times when compared with real power performance index case.

6.3 RECOMMENDATIONS FOR FURTHER STUDIES

The following recommendations are made from this thesis:

(1) The results of frequency prediction and dynamic load flow can be compared with long term dynamic simulation.

(2) Frequency dependence of loads can be included in frequency prediction formula.

APPENDICES

APPENDIX A

Parameters of Generator, Governor and turbine calculated on 100 MVA base.

Unit No. k	$T_{1,k}$	$T_{2,k}$	$T_{3,k}$	$T_{4,k}$	$A_{1,k}$	$A_{2,k}$	H_k	D_k	ξ_k	Rating
1	0.40	0.40	10.00	6.00	0.30	0.50	42.00	4.00	0.70	1040
2	0.30	0.40	8.00	4.00	0.30	0.36	30.30	9.75	0.50	640
3	0.40	0.45	9.50	5.00	0.30	0.43	35.80	10.00	0.60	725
4	0.30	0.45	10.50	6.00	0.30	0.36	28.60	10.00	0.49	1000
5	0.45	0.50	7.00	0.00	0.35	1.00	26.00	3.00	0.43	600
6	0.45	0.42	10.00	5.50	0.35	0.46	34.80	10.00	0.58	800
7	0.40	0.40	10.20	6.00	0.30	0.43	26.40	8.00	0.44	580
8	0.43	0.47	8.00	4.70	0.30	0.57	24.30	9.00	0.40	564
9	0.47	0.41	7.50	0.00	0.40	1.00	34.50	14.00	0.57	865
10	0.30	0.45	10.50	6.00	0.30	0.50	100.00	10.00	1.66	2000

APPENDIX B

DESIGN CRITERIA FOR LINEAR TYPE LOAD SHED SCHEME

I Determination of Optimum Load Shedding Amount

An optimum amount of load shedding could be determined to allow recovery to normal frequency without causing operation of the turbine-generator under-frequency relays. The criteria used in evaluating the optimum amount of load shedding and its coordination with the turbine-generator relaying protection scheme are as follows [10]:

a) The maximum amount of system load shedding employed should be effective in preventing underfrequency excursions below 57.0 Hz for longer than 30 cycles (60 cycle base) and/or the system frequency should be able to recover and settle at 60 Hz following a disturbance.

b) The system frequency should recover quickly enough to provide sufficient margin with the planned turbine-generator under-frequency protection schemes.

c) Frequency overshooting due to excessive overshedding of load should be limited to less than 61-62 Hz in order to avoid infringement on unit over-frequency limits.

It is observed in the previous work that the loss of generation which causes a certain system overload requires the same amount of load shedding to recover frequency to 60 Hz.

II Selection of Frequency Set-points

All of the large turbine-generators on the system are not rated for continuous operation below 59.5 Hz or 59.4 Hz depending on manufacture. Thus, load shedding should be initiated at these levels to help maintain continuous operation above these levels. A load shed program starting at 59.5 Hz would be more effective in minimizing the depth of the underfrequency response for a heavy overload than would a similar program which had a lower initial frequency set-point.

Once the initial set point was selected, the remaining set-points were chosen to be 0.2 Hz to 0.4 Hz apart. Ideally, 0.2 Hz separation worked the best on the upper frequency set-points; 0.3 Hz or 0.4 Hz worked best on the lower steps in reducing overshedding tendencies.

III Number of Steps and Load Per Step

All existing load shed schemes are using about 40 percent load shedding because it appears to be the most promising amount to pursue. The load shedding schemes with few steps would tend to be the worst from the standpoint of overshedding on lighter loads. It was found that larger loads on the upper steps not only provide better coordination with the turbine-generator underfrequency protection scheme, but also more effectively limited overshedding on moderate to heavy overloads. The schemes, with six or more steps and less load per step on the lower steps, had the best overall profile for minimizing overshedding.

APPENDIX C

IEEE 39-Bus System Data

Input Bus Data

Bus No.	Voltage	Generation Real Power MW	Generation Reactive Power MVAr	Load Real Power MW	Load Reactive Power MVAr
1	1.08424	000.00	0.00	0.00	0.00
2	1.05920	563.30	0.00	9.20	4.60
3	1.04918	650.00	0.00	0.00	0.00
4	0.98437	632.00	0.00	0.00	0.00
5	0.98258	508.00	0.00	0.00	0.00
6	1.00689	650.00	0.00	0.00	0.00
7	1.01500	560.00	0.00	0.00	0.00
8	1.02705	540.00	0.00	0.00	0.00
9	1.01500	830.00	0.00	0.00	0.00
10	1.03492	1000.00	0.00	1104.00	250.00
11	0.00000	0.00	0.00	0.00	0.00
12	0.00000	0.00	0.00	8.50	88.00
13	0.00000	0.00	0.00	0.00	0.00
14	0.00000	0.00	0.00	0.00	0.00
15	0.00000	0.00	0.00	320.00	153.00
16	0.00000	0.00	0.00	329.40	32.30
17	0.00000	0.00	0.00	0.00	0.00
18	0.00000	0.00	0.00	158.00	30.00
19	0.00000	0.00	0.00	0.00	0.00
20	0.00000	0.00	0.00	680.00	103.00
21	0.00000	0.00	0.00	274.00	115.00
22	0.00000	0.00	0.00	0.00	0.00
23	0.00000	0.00	0.00	247.50	84.60
24	0.00000	0.00	0.00	308.60	-92.20
25	0.00000	0.00	0.00	224.00	47.20
26	0.00000	0.00	0.00	139.00	17.00
27	0.00000	0.00	0.00	281.00	75.50
28	0.00000	0.00	0.00	206.00	27.60
29	0.00000	0.00	0.00	283.50	26.90
30	0.00000	0.00	0.00	0.00	0.00
31	0.00000	0.00	0.00	0.00	0.00
32	0.00000	0.00	0.00	322.00	2.40
33	0.00000	0.00	0.00	500.00	184.00
34	0.00000	0.00	0.00	0.00	0.00
35	0.00000	0.00	0.00	0.00	0.00
36	0.00000	0.00	0.00	0.00	0.00
37	0.00000	0.00	0.00	233.80	84.00
38	0.00000	0.00	0.00	522.00	176.00
39	0.00000	0.00	0.00	0.00	0.00

Line data:

Line	SB	EB	Series Impedance R p.u.	Series Impedance X p.u.	Half Line Charging Susceptance p.u.	Tap
1	30	31	0.0035	0.0411	0.3493	1.000
2	30	10	0.0010	0.0250	0.3800	1.000
3	31	32	0.0013	0.0151	0.1263	1.000
4	31	25	0.0070	0.0086	0.0730	1.000
5	32	33	0.0013	0.0213	0.1107	1.000
6	32	18	0.0011	0.0133	0.1069	1.000
7	33	34	0.0008	0.0128	0.0671	1.000
8	33	14	0.0008	0.0129	0.0641	1.000
9	34	35	0.0002	0.0026	0.0217	1.000
10	34	37	0.0008	0.0112	0.0738	1.000
11	35	36	0.0006	0.0092	0.0560	1.000
12	35	11	0.0007	0.0082	0.0694	1.000
13	36	37	0.0004	0.0046	0.0390	1.000
14	37	38	0.0023	0.0363	0.1902	1.000
15	38	10	0.0010	0.0250	0.6000	1.000
16	39	11	0.0004	0.0043	0.0364	1.000
17	39	13	0.0004	0.0043	0.0364	1.000
18	13	14	0.0009	0.0101	0.0861	1.000
19	14	15	0.0018	0.0217	0.1830	1.000
20	15	16	0.0009	0.0094	0.0850	1.000
21	16	17	0.0007	0.0089	0.0671	1.000
22	16	19	0.0016	0.0195	0.1520	1.000
23	16	21	0.0008	0.0135	0.1274	1.000
24	16	24	0.0003	0.0059	0.0340	1.000
25	17	18	0.0007	0.0082	0.0659	1.000
26	17	27	0.0013	0.0173	0.1609	1.000
27	21	22	0.0008	0.0140	0.1292	1.000
28	22	23	0.0006	0.0096	0.0923	1.000
29	23	24	0.0022	0.0350	0.1810	1.000
30	25	26	0.0032	0.0323	0.2560	1.000
31	26	27	0.0014	0.0147	0.1198	1.000
32	26	28	0.0043	0.0474	0.3903	1.000
33	26	29	0.0057	0.0625	0.5140	1.000
34	28	29	0.0014	0.0151	0.1240	1.000
35	12	11	0.0016	0.0435	0.0000	1.006
36	12	13	0.0016	0.0435	0.0000	0.975
37	35	2	0.0000	0.0250	0.0000	1.005
38	39	3	0.0000	0.0200	0.0000	1.015
39	19	4	0.0007	0.0142	0.0000	0.975
40	20	5	0.0009	0.0180	0.0000	1.010
41	22	6	0.0000	0.0143	0.0000	1.015
42	23	7	0.0005	0.0272	0.0000	0.950
43	25	8	0.0006	0.0232	0.0000	1.046
44	31	1	0.0000	0.0181	0.0000	0.996
45	29	9	0.0008	0.0156	0.0000	0.935
46	19	20	0.0007	0.0138	0.0000	1.015

Load Flow Results - Bus Data

Bus No.	Voltage	Generation		Load	
		Real Power MW	Reactive Power MVAr	Real Power MW	Reactive Power MVAr
1	1.0842	277.5	228.4	0.0	0.0
2	1.0592	563.3	273.9	9.2	4.6
3	1.0471	650.0	283.9	0.0	0.0
4	0.9844	632.0	-54.4	0.0	0.0
5	0.9826	508.0	193.7	0.0	0.0
6	1.0069	650.0	274.3	0.0	0.0
7	1.0150	560.0	-7.1	0.0	0.0
8	1.0270	540.0	127.3	0.0	0.0
9	1.0150	830.0	-72.4	0.0	0.0
10	1.0349	1000.0	108.3	1104.0	250.0
11	1.0125	0.0	0.0	0.0	0.0
12	0.9831	0.0	0.0	8.5	88.0
13	1.0121	0.0	0.0	0.0	0.0
14	0.9992	0.0	0.0	0.0	0.0
15	0.9740	0.0	0.0	320.0	153.0
16	0.9778	0.0	0.0	329.4	32.3
17	0.9887	0.0	0.0	0.0	0.0
18	0.9962	0.0	0.0	158.0	30.0
19	0.9671	0.0	0.0	0.0	0.0
20	0.9563	0.0	0.0	680.0	103.0
21	0.9724	0.0	0.0	274.0	115.0
22	0.9869	0.0	0.0	0.0	0.0
23	0.9739	0.0	0.0	247.5	84.6
24	0.9808	0.0	0.0	308.6	-92.2
25	1.0485	0.0	0.0	224.0	47.2
26	1.0020	0.0	0.0	139.0	17.0
27	0.9895	0.0	0.0	281.0	75.5
28	0.9690	0.0	0.0	206.0	27.6
29	0.9607	0.0	0.0	283.5	26.9
30	1.0483	0.0	0.0	0.0	0.0
31	1.0429	0.0	0.0	0.0	0.0
32	1.0121	0.0	0.0	322.0	2.4
33	0.9955	0.0	0.0	500.0	184.0
34	1.0054	0.0	0.0	0.0	0.0
35	1.0091	0.0	0.0	0.0	0.0
36	0.9986	0.0	0.0	233.8	84.0
37	0.9976	0.0	0.0	522.0	176.0
38	1.0318	0.0	0.0	0.0	0.0
39	1.0177	0.0	0.0	0.0	0.0

Line Data

Line	SB	EB	Line Flows	
			Real Power	Reactive Power
1	31	30	124.2	-40.3
2	10	30	-123.4	-69.1
3	32	31	-382.8	-170.6
4	25	31	203.0	-98.4
5	33	32	-82.4	-77.1
6	18	32	22.3	-126.0
7	34	33	159.7	65.8
8	14	33	257.7	13.9
9	35	34	474.5	110.3
10	37	34	-313.4	-45.2
11	36	35	-420.7	-82.2
12	11	35	345.6	13.4
13	37	36	-187.9	-5.2
14	38	37	18.5	86.0
15	10	38	19.0	-20.1
16	11	39	-348.4	-90.0
17	13	39	-298.1	-104.8
18	14	13	-292.0	-101.6
19	15	14	-34.1	-119.1
20	16	15	287.9	11.7
21	17	16	-200.3	135.7
22	19	16	452.7	-75.3
23	21	16	329.9	-56.8
24	24	16	40.5	47.0
25	18	17	-180.6	104.6
26	27	17	-19.5	-1.8
27	22	21	607.8	88.0
28	23	22	-42.4	-133.8
29	24	23	-348.5	55.5
30	26	25	-78.5	-148.7
31	27	26	-262.9	-59.9
32	28	26	137.0	-93.0
33	29	26	189.4	-91.9
34	29	28	345.0	-80.6
35	11	12	2.3	68.5
36	13	12	7.2	67.4
37	2	35	554.7	248.2
38	3	39	656.4	194.5
39	4	19	622.7	117.2
40	5	20	512.2	142.2
41	6	22	659.9	172.1
42	7	23	533.5	182.5
43	8	25	559.3	-75.2
44	1	31	276.4	253.7
45	9	29	790.2	360.5
46	20	19	-182.2	-63.3

APPENDIX D

System conditions for different margin to deficiency ratio's and disturbances.

MDR	ΔP_L p.u.	Generator Real Power 1	2	3	4	5	6	7	8	9	10
	1.0	1016.9	637.2	722.3	986.7	596.7	794.6	579.3	563.1	863.7	1963.7
	2.0	989.5	634.6	719.7	974.2	593.5	789.5	578.6	562.3	862.5	1929.8
1.02	5.0	907.6	626.8	712.1	936.6	584.2	774.2	576.6	559.9	859.0	1827.8
	10.0	771.7	613.7	699.3	873.7	568.4	748.5	573.1	555.8	853.0	1656.9
	15.0	637.5	600.6	686.4	810.8	552.7	722.9	569.7	551.7	847.0	1485.9
	1.0	1016.1	637.1	722.2	986.3	596.6	794.4	579.3	563.1	863.7	1962.7
	2.0	987.8	634.5	719.6	973.4	593.4	789.2	578.6	562.3	862.5	1927.7
1.05	5.0	903.5	626.4	711.7	934.8	583.7	773.4	576.5	559.7	858.8	1822.7
	10.0	763.7	612.9	698.5	870.0	567.5	747.0	572.9	555.5	852.6	1646.8
	15.0	625.3	599.4	685.3	805.0	551.3	720.5	569.4	551.3	846.5	1470.2
	1.0	1012.1	636.8	721.8	984.5	596.1	793.7	579.2	563.0	863.5	1957.9
	2.0	979.8	633.7	718.8	969.7	592.4	787.7	578.4	562.0	862.1	1917.8
1.20	5.0	883.6	624.5	709.8	925.6	581.4	769.7	576.0	559.1	857.9	1797.8
	10.0	723.4	609.0	694.7	851.2	562.8	739.3	571.9	554.3	850.8	1595.6
	15.0	565.7	593.5	679.5	776.8	544.2	709.0	567.9	549.4	843.8	1393.4
	1.0	1003.9	636.0	721.1	980.8	595.2	792.2	579.0	562.7	863.2	1947.8
	2.0	963.5	632.1	717.3	962.3	590.6	784.6	578.0	561.5	861.4	1897.5
1.50	5.0	843.3	620.6	706.0	907.0	576.7	762.1	574.9	557.9	856.2	1747.2
	10.0	644.2	601.2	687.1	814.0	553.5	724.2	569.9	551.9	847.3	1494.5
	15.0	448.9	581.8	668.1	721.0	530.2	686.3	564.8	545.8	838.5	1241.7
	1.0	989.0	634.6	719.7	974.0	593.5	789.4	578.6	562.3	862.5	1929.2
	2.0	937.5	629.7	714.9	950.4	587.6	779.8	577.3	560.8	860.3	1865.2
2.00	5.0	776.5	614.2	699.7	876.0	569.0	749.4	573.3	555.9	853.2	1663.0
	10.0	513.6	588.3	674.4	752.0	538.0	698.9	566.5	547.8	841.4	1326.0
	15.0	257.0	562.5	649.2	627.9	507.0	648.3	559.8	539.7	829.6	989.0
	1.0	961.8	632.0	717.2	961.6	590.4	784.3	577.9	561.5	861.3	1895.5
	2.0	880.9	624.2	709.6	924.3	581.1	769.2	575.9	559.1	857.8	1794.4
3.00	5.0	644.2	601.2	687.1	814.0	553.5	724.2	569.9	551.9	847.3	1494.5
	10.0	257.0	562.5	649.2	627.9	507.0	648.3	559.8	539.7	829.6	989.0
	1.0	937.0	629.6	714.8	950.1	587.5	779.7	577.3	560.7	860.3	1864.5
	2.0	829.9	619.3	704.8	900.8	575.2	759.6	574.6	557.5	855.6	1730.4
4.00	5.0	513.6	588.3	674.4	752.0	538.0	698.9	566.5	547.8	841.4	1326.0
	10.0	367.6	474.3	574.6	584.1	414.3	538.4	488.4	467.2	753.8	626.6

NOMENCLATURE

NOMENCLATURE

$A_{j,k}$ = j^{th} Constant of k^{th} machine

$A_{v,k}$ = Valve area of k^{th} machine

$C_{j,k}$ = j^{th} Constant of k^{th} machine

D_k = Damping of k^{th} machine

D_T = Total damping of the system

H_k = Inertia of k^{th} machine

H_T = Total inertia of the system

f_{min} = Minimum frequency after initial disturbance

$f_{min,\ell s}$ = Minimum frequency after load shedding

M_k = Margin of k^{th} machine

MDR = Margin to deficiency ratio

NG = Number of machines in the sample system

P_{ek} = Real power of k^{th} generator

P_{jk} = power flow in k^{th} line

P_{ℓ} = MW flow in line ℓ

PI = Performance index

Q_{ek} = Reactive power of k^{th} generator

$R_{d,k}$ = Governor droop of k^{th} generator

$R_{\ell max,k}$ = Upper limit of rate of change of valve area of k^{th} governor

$R_{\ell min,k}$ = Lower limit of rate of change of valve area of k^{th} governor

$R_{v,k}$ = Rate of change of valve area of k^{th} governor

$t_{d\ell}$ = Delay time of the relay

$t_{\ell s}$ = Time at which load is shed

t_{min} = Time of occurance of minimum frequency after initial disturbance

$t_{min,\ell s}$ = Time of occurance of minimum frequency after load shedding

$T_{d,k}$ = Time at which the valve reaches it area limit

$U(t)$ = Unit step function

v = Bus voltage

$\Delta P_{e,k}$ = Electrical power of k^{th} machine

ΔP_{eT} = Total electrical power of the system

ΔP_{L} = Initial disturbance to the system

$\Delta P_{\ell s}$ = Amount of load shed

$\Delta P_{m,k}$ = Mechanical power of k^{th} machine

ΔP_{mT} = Total mechanical power of the system

θ	=	Bus angle
ξ_k	=	A constant whose value is dependent on the response of characteristics of the power plant
ω	=	Average system frequency
$\Delta\omega$	=	Change in system frequency

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